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Effective DG Incentive and DSR Incentive for Distribution Network Operators

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Effective DG Incentive and DSR Incentive for Distribution Network Operators

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ABSTRACT

Countries around the world set ambitious targets to substantially reduce their greenhouse gasses emissions, including those which come from electricity sector. This requires a transition to a low carbon electricity generation and supply system, which in part, can be met by increasing distributed generation (DG) connection and implementing demand side response (DSR) programme on distribution network. Therefore, the role of distribution network operators (DNOs) in facilitating the connection of new DG and the implementation of DSR programme is vital. In order to encourage DNOs to be more active in the low carbon transition, the energy regulator needs to set up financial incentives for DNOs.

Current DG incentive mechanism, which is applied in the UK, aims to incentivise DNOs based on the amount of DG capacity connected to the network. Consequently, in a generation-dominated area, the incentives might not be sufficient to cover the reinforcement required for connecting DGs, which in turn, the output energy from DGs will be excessively curtailed. Therefore, this research proposes a new approach, called energy-based DG incentive mechanism. This mechanism will incentivise DNOs based on the utilization of available DG energy on the network and its relation with the requirement of network reinforcement.

In terms of DSR incentives, different mechanisms have been applied in some countries, including Australia and USA. Some of the mechanisms incentivise DNOs based on the investment cost or forgone revenue related to DSR initiatives, as implemented in demand management incentive and rate of return mechanisms. Other mechanisms aim to incentivise DNOs based on the energy savings or avoided costs of supply associated with DSR participation, as implemented in shared savings and avoided cost mechanisms. Those mechanisms operate independently without any correlation between them. Therefore, this research develops a new approach to assess the relation between DSR investment cost and DSR participation, called energy-based DSR incentive mechanism. This mechanism will incentivise DNOs based on the utilization of available DSR energy on the network and its relation with the required investment.

Comparing with current incentive mechanisms, both energy-based DG incentive and energy-based DSR incentive can reflect the effectiveness of DNOs to deal with the required investments in association with DG connection and DSR implementation on their network.

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LIST OF ABBREVIATIONS

ADR	Automated Demand Response
ANM	Active Network Management
C2C	Capacity to Customers
CCGTs	Combined Cycle Gas Turbines
DECC	Department of Energy and Climate Change
DG	Distributed Generation
CHP	Combined Heat and Power
CLNR	Customer Led Network Revolution
DM	Demand Management
DNOs	Distribution Network Operators
DNSPs	Distribution Network Service Providers
DR	Demand Response
DSR	Demand Side response
EE	Energy Efficiency
FERC	Federal Energy Regulatory Council
FITs	Feed-in Tariffs
IFI	Innovation Funding Incentives
IPART	Independent Pricing and Regulatory Tribunal
IPSA	Integrated Power System Analysis
ISOs	Independent System Operators
LCOEG	Levelised Cost of Energy Generation
kW	kilo Watt
kWh	kilo Watt hour
LCN	Low Carbon Networks

LEC	Levy Exemption Certificate
LMP	Locational Marginal Price
MVA	Mega Volt Ampere
MVAr	Mega Volt Ampere reactive
MW	Mega Watt
MWh	Megawatt hour
NSPs	Network Service Providers
NYISO	New York Independent System Operator
OFGEM	Office of Gas and Electricity Markets
PV	Photovoltaic
REGO	Renewable Energy Guarantees of Origin
RET	Renewable Energy Target
ROC	Renewables Obligation Certificate
RPZ	Registered Power Zone
RTO	Regional Transmission Organisation
STOR	Short Term Operating Reserve
SWIS	South-West Interconnected System
TNOs	Transmission Network Operators
TSOs	Transmission System Operators
WACC	Weighted Average of Cost of Capital
WEM	Wholesale Electricity Market

LIST OF SYMBOLS

ΔP	the changes of real power injection
ΔQ	the changes of reactive power injections
$\Delta\delta$	the changes of bus voltage angles
$\Delta\lvert V\rvert$	the changes of bus magnitudes
J_1, J_2, J_3 and J_4	the elements of Jacobian matrix
JB_1, JB_2, JB_3 and JB_4	the elements of the inverse of the Jacobian matrix
$\mathrm{Network}_{\mathrm{power\ Flow}}$	the line's power flow
$\mathrm{Network}_{\mathrm{apacity\ rate}}$	the capacity rate of the line
R_k	the resistance of line-k
P_k	the real power of line-k
Q_k	the reactive power of line-k
V_k	the voltage magnitude of bus-k
$P\_Loss\ (k, k+1)$	the power losses between bus-k and bus-k+1
$P_{T,Loss}$	the total power losses of the feeder
dV	the changes of voltage level
kV_0	the initial voltage magnitude
kV_n	the voltage magnitude after a new DG connection
$dS_{powerflow}$	the changes of the network utilization
$S_{powerflow-o}$	the initial power flow
$S_{powerflow-n}$	the power flow of after a new DG connection
dS_{Losses}	the changes of power losses
$S_{Losses-o}$	the initial power losses
$S_{Losses-n}$	the power losses after a new DG connection
P_m	the real power of line-m
Q_m	the reactive power of line-m

V_i	the voltage magnitude of bus-i
V_k	the voltage magnitude of bus-k
δ_i	the voltage angle of bus-i
δ_k	the voltage angle of bus-k
P_m^0	the base case active power flow
ΔP_m	the incremental active power flow
$\frac{\partial P_m}{\partial P_i}$	the sensitivity of bus i to line m in term of real power injection
$\frac{\partial P_m}{\partial Q_i}$	the sensitivity of bus i to line m in term of reactive power injection
$\Delta DG_{p,m}$	the amount of the DG real power output curtailment at node-m
ΔP_{ik}	the change in real power which is flowing from node i to node k
$\frac{dP_{ik}}{dGD_{p.m}}$	the sensitivity factor of the line between bus-i and bus-k to the connection of DG-p at bus-m
$\propto$	the target utilisation of the congested component
$S_{i,k}^{lim}$	the thermal rating of the congested component
$'S_{i,k}$	the initial apparent power flow between node-i and node-k
$'Q_{i,k}$	the initial reactive power flow between node-i and node-k
$''Q_{i.k}$	the target reactive power flowing from node-i to node-k
$P_{Loss-i,k}$	the initial active power losses between node-i and node-k
$Q_{Loss-i,k}$	the initial reactive power losses between node-i and node-k
$DG_{p,EnergyCurtail}$	the energy curtailment of DG-p at bus m
$\Delta G_{p.m}$	the amount of DG-p output curtailment
$DG_{p.cf}$	the capacity factor of DG-p
$DG_{p.oprtime}$	the operation time of DG-p
$DG_{p,CurtailCost}$	the energy curtailment cost of DG-p at bus m
$DG_{p.LCOEG}$	the levelised cost of energy generation of DG-p

$\Delta DGmax_{p.m}$	the maximum output of DG_p to be curtailed
$InvCost_m$	Investment Cost to reinforce line –m
$\Delta DG_{p.m}$	the required output of DG_p to be curtailed
$DG_{p,EnergyCurtailMax}$	the maximum energy curtailment of DG_p
$Line_{ik,capacity}$	the available network capacity prior to DG connection
$EnConvey_p^m$	the amount of energy from DG_p without reinforcing lime-m
$DG_{p,EnergyReq}$	the minimum requirement for energy to be conveyed from DG_p
$DG_{p,EnergyMax}$	the maximum energy that can be generated from the DG_p
$DG_{p,Cap}$	the capacity of DG_p
$DG_{p,pf}$	the power factor of DG_p
$DG_{p,EnergyCurtail}$	the energy curtailment of DG_p
DG_{EU}	the energy utilization of DG_p
DG_{UC}	the unit cost of DG incentive
DG_{IR}	the rate of DG incentive
DG_{Inc}	the energy-based DG incentive
DG_{EUMin}	the minimum DG energy utilization
DG_{IncMin}	the minimum threshold of energy-based DG incentive
DG_{IncMax}	the maximum threshold of energy-based DG incentive
DSR_{EU}	the utilization of DSR energy
DSR_{EAc}	the actual DSR energy participation
DSR_{EAv}	the available DSR energy on the network
DSR_{CapAc}	the actual DSR capacity participation
DSR_{CapAv}	the available DSR capacity on the network
$time_{act}$	the actual DSR participation time
$time_{req}$	the required DSR participation time
DSR_{Cost}	the cost of DSR project

$\mathrm{DSR}_{\mathrm{UC}}$	the unit cost of DSR incentive
$\mathrm{DSR}_{\mathrm{IR}}$	the rate of DSR incentive
nper	the component’s lifetime
$\mathrm{DSR}_{\mathrm{Inc}}$	the energy-based DSR incentive
$\mathrm{DSR}_{\mathrm{IncMax}}$	the maximum threshold of energy-based DSR incentive

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1 INTRODUCTION

1.1 BACKGROUND

1.1.1 Use of Renewable Energy Sources to Tackle Climate Change

Nowadays climate change has become one of the most concerned problems around the world. This phenomenon can cause sea level rises, temperature rises and extreme weather events, such as heat waves, storms, flood and drought, that threaten not only peoples' health and way of life but also the existence of plants and animals. The main cause of climate change is the emission of greenhouse gasses, like carbon dioxide and methane. One of the sources of carbon dioxide comes from energy production which uses fossil fuels to generate energy. In order to tackle the effects of climate change and to minimise further dangerous risk, one of the most appropriate ways is by decarbonising energy production.

Renewable energy sources are important and beneficial, not only to replace fossil fuels in terms of the reduction of carbon emission in energy generation, but also to cope with the need for sustainable sources to fulfil the growth of demand for energy over the next few decades, which is combined with the depletion of fossil fuels in the near future. Some countries have a specific target to reduce their dependence on fossil-fuelled power plants and turn to renewable energy power plants.

UK has targeted that 15% of energy will be taken from renewable sources by 2020. It is projected that 30% of the 2020 target for electricity generation could be met by utilizing onshore and offshore wind, but important contributions from hydro, sustainable bio-energy, marine sources and small-scale technologies, must be considered as well [1].

USA has targeted that 20% of total power consumed will be taken from Renewable Power by 2020 [2]. This target is expected to be achieved gradually, i.e. not less than 10 percent in 2015, not less than 15 percent in 2016 and 2017, not less than 17.5 percent in 2018 and 2019 and finally, not less than 20 percent by 2020 [3].

Through the Renewable Energy Target (RET) scheme, Australia also targeted to reach 20% of its electricity production derived from renewable sources by 2020. The RET is designed to transform Australia's energy generation mix to be cleaner and to have more various sources to support the growth and employment in renewable energy sector [4].

1.1.2 Deployment of Distributed Generation (DG)

In terms of electricity generation and supply, there are two methods which have significant impact on achieving the target in reducing greenhouse gasses emissions and increasing the penetration of renewable energy sources in electricity production, i.e. increasing the connection of distributed generation (DG) and implementing demand side response (DSR).

The first method to achieve the targets is by increasing the connection of distributed generation (DG). Since most of DGs come from renewable resources they can contribute in reducing carbon emissions from the electricity sector and increasing the use of renewable sources to replace fossil fuels.

Distributed generations (DGs) are directly connected to the distribution network rather than transmission network and the electricity generated is being used locally rather than distributed to a wider area, so that, the loading level of branches and substation transformers at which they are connected might decrease. This can substantially reduce energy losses during energy transmission [5][6][7] and improve supply reliability [8]. It might also cause the deferment of distribution and transmission networks investment.

The presence of DGs on electricity distribution network has also changed the nature of the network. In a conventional network, the power flows in one-directional way, from the transmission or distribution networks to the demands or loads. On the network with connected DGs, the power flows in bi-directional way, from the transmission or distribution networks to the demands or loads, and vice versa [9]. This requires more sophisticated network configuration and technology application, such as smart grid and smart meters. A mechanism called active network management (ANM) can also be deployed to deal with this issue. This mechanism allows distribution network operators (DNOs) to automatically control and coordinate devices (demand) and resources (DGs) to manage the network constraints [20].

Currently, according to some reports, the penetration of DGs on distribution network is quite low in some countries, such as Australia, United States of America and the United Kingdom. DGs contribute around 1.36% of the total electricity generation in Australia [10], 18.98% of the total electricity generation in US [11] and approximately 7.5% of the total electricity generation in the UK [12].

1.1.3 Implementation of Demand Side Response (DSR) Programme

The second method to achieve the target is by implementing demand side response (DSR). The implementation of DSR, through demand reduction and demand shifting mechanisms, has the potential to reduce carbon emissions. These mechanisms will impact on the more efficient use of electricity generation as well as minimising the use of less efficient generation plants, which mostly come from fossil fuelled power plants [13][14].

Demand Side Response (DSR) is described as a mechanism to reduce peak demand, as well as to respond the requirement to balance the system, due to electricity demand is greater than total available electricity, either by reducing electricity demand, shifting the times of electricity consumption at peak times to other off-peak times in a day, or by running on-site generation [15][16][17].

Besides contributing in carbon emissions reduction, the implementation of DSR on electricity distribution network can provides other benefits, not only for the DNO but also for all associated parties who participate in distributing electricity, including suppliers, retailers, aggregators and consumers.

DSR, in the forms of peak demand reduction, either by demand reduction or demand shifting, can reduce the requirement of new network investment as well as reduce the required capacity from additional electricity generation [18]. Peak demand reduction also impacts on reducing the price of electricity paid by consumers, since they can avoid the use of expensive electricity prices at peak times [18]. DSR can also reduce the scarcity of electricity by running on-site generation, at times when electricity supply from transmission network is disturbed [19]. This mechanism will maintain the reliability of supply to the customers as well as reduce the emissions due to network losses and mitigate negative environmental impacts from fossil-fuelled power plants [17][19].

Some countries, such as Australia, US and the UK have run some DSR trials on their electricity distribution network. The trials show that the implementation of DSR can reduce the annual peak demand by 10% in USA [21], by 11.5% in Australia [22] and by 10% in the UK [23].

1.1.4 Current Incentive Mechanisms for DNOs

A. DG Incentive Mechanism

The presence of DGs and the implementation of DSR programme is important to move towards the low carbon transition because they can contribute in reducing the carbon emissions from electricity sector. Since DG Connection and DSR programme are implemented on distribution networks, the role of DNOs is vital, considering they are responsible for network operation, maintenance and development.

Currently, DNOs do not have huge experience in connecting large amount of DGs and implementing DSR programmes. Therefore, the government or the energy regulators need to provide supporting incentive mechanisms which can encourage DNOs to be more active in the development of DGs and DSR programmes.

DG incentive mechanism, which is currently applied in the UK [24], aims to give incentives for distribution network operators based on the DG capacity that DNOs have connected to the network. This incentive mechanism is uniform, means that the value of the incentives given to the DNOs for them to connect per unit DG capacity is the same across the country.

This research analysis shows that different DG technologies have different value of DG parameters, including capacity factor, electricity generation cost and operational time. These parameters will determine the amount of energy that can be generated by a particular DG. This means that the same DG capacity from different technology will generate different amount of energy. The analysis also shows that DG connection at different locations on a network, i.e. at a generation-dominated area and at a demand-dominated area, will have different effects. DG connection at a generation-dominated area will cause the power flow to increase. As the amount of power flow increases, the power losses will increase as well. Meanwhile, the opposite effects are resulted from the connection of DG at a demand-dominated area. This connection will decrease the power flow on related lines. As a result, the power losses of those lines will decrease as well. Considering these results, current DG incentive mechanism which is mainly based on the DG capacity, might not give equal treatment for DG connection with different DG technologies and at different location on the network.

Capacity-based mechanism also can lead to an undesirable consequence, where the incentives might not sufficient to cover the reinforcement required to connect DGs in the generation-dominated area, which in turn, DNOs will have to excessively curtail DG generation. There will therefore be the case to design DG incentives according to the actual energy conveyed by DNOs, instead of DG capacity connection, as significant energy may have to be curtailed. Through energy based DG incentives, DNOs can provide better economic message to renewable investors of the likely usable energy from their generation plant, encouraging a more balanced generation/network development.

B. DSR Incentive Mechanism

For the purpose of incentivising DNOs associated with DSR implementation on their distribution network, some countries including Australia and USA have applied different incentive mechanisms, including demand management incentive, rate of return, shared savings and avoided cost mechanisms.

Demand management incentive mechanism, which is currently applied in Australia, aims to incentivise DNOs based on the investment costs and forgone revenues associated with DSR initiatives [25]. Shared savings mechanism allows DNOs to receive a percentage share of the energy saving as a result of Demand Response (DR) or Energy Efficiency (EE) program. Rate of return mechanism allows DNOs to earn profit on DR and EE investment, based on their rate base. Avoided cost mechanism allows DNOs to receive a percentage of their avoided supply costs as their DR and EE savings compensation. The last three mechanisms are currently applied in USA [26].

Currently, the existing DSR incentive mechanisms operate independently without any correlation between them. Therefore, this research develops a new approach to assess the relation between the required investment to implement DSR programme and the actual DSR energy participation. Through energy based DSR incentives, DNOs can be encouraged to be more effective in implementing DSR programme on their network.

1.1.5 Effective Incentive Mechanisms for DNOs

This research proposes two new approaches to set incentives for DNOs associated with DG connection and DSR implementation on distribution networks, i.e. energy-based DG incentive and energy-based DSR incentive mechanisms.

Energy-based DG incentive mechanism is a mechanism to incentivise DNOs in connecting DG on their network, based on the utilization of available DG energy on the network and its relation with the requirement of network reinforcement. The higher the energy from the connected DG can be conveyed, the higher the incentive for DNOs. The maximum incentive will be given to DNOs if the available DG energy can be fully utilized. Meanwhile, the minimum incentive will be given if the connected DG can only convey energy at its minimum requirement. If the connected DG cannot meet the minimum requirement, DNOs will not be incentivised.

In a generation-dominated area, a new DG connection might cause the network capacity is not sufficient to accommodate the total DG capacity. This will result in two options, either by curtailing the energy from the connected DG to suit the network capacity, or by reinforcing the network to accommodate all available DG capacity. In financial point of view, the less cost the better. If the network reinforcement is chosen, the value of a new investment must be higher, or more worthy, than the value of energy curtailment. At the point where the value of DG curtailment is equal to the value of network reinforcement, the minimum requirement for energy to be conveyed is obtained.

Hence, energy-based DG incentive mechanism can encourage DNOs to be more effective in in facilitating DG connection on their network by considering the utilization of available DG energy on their network.

This research also proposes an energy-based DSR incentive mechanism, i.e. a mechanism to incentivise DNOs in association with the implementation of DSR programme on their network. This mechanism considers two factors in implementing DSR programme, including the investment cost and the utilization of available DSR energy on the network.

The investment cost includes all costs that fall under DNOs responsibility, such as communication system upgrade cost, software cost, consumer education cost and programme administration and management cost. The higher the investment cost the higher the incentive for the DNOs.

Besides the investment cost, the energy-based DSR incentive for DNOs also considers the utilization of available DSR energy on the network. The available DSR energy is based on the agreement between customers and DNOs or suppliers on how much energy can be participated in DSR programme. The higher the DSR energy utilization, the higher the incentive for the DNOs. The maximum DSR incentive will be given to DNOs if the available DSR energy can be fully utilized.

Through energy-based DSR incentives, DNOs can be encouraged to be more effective in their investment to deal with the implementation of DSR programme on their network.

1.2 OBJECTIVES

The objectives of this thesis are:

1) To assess the impact of DG connections to an existing distribution network, especially in a generator-dominated area and in a demand-dominated area, in terms of voltage level, power losses and network capacity utilization.
2) To develop a method to form an effective energy-based DG Incentive for DNOs based on the utilization of the available DG energy on the network.
3) To assess the impact of DSR on network performance, i.e. voltage level, power losses and network capacity utilization, through demand reduction, demand shifting and running on-site generation.
4) To develop a method to form an effective energy-based DSR Incentive for DNOs based on the utilization of the available DSR energy on the network.
5) To develop a method to form a mixed energy-based DG and DSR Incentives for DNOs related to the connection of a DG and the implementation of DSR programme on the same distribution network.

1.3 MAIN CONTRIBUTIONS

The main contributions of this thesis can be summarised as follows:

1) This research develops a new approach to assess the impact of DG connection on the performance of a distribution network. The assessment is carried out by analysing the effects of DG connection at a generation-dominated area and at a demand-dominated area, in terms of voltage level, power losses and network capacity utilization. The results of this assessment have been published in two different papers.
2) This research develops a new approach in incentivising DNOs to promote DG connection on their distribution network. DG incentive is given based on the utilization of available DG energy on the network and its relation with the requirement of network reinforcement. Since the value of DG incentive based on the actual energy, a DNO who can convey all available DG energy on their network will receive incentives at its maximum value. However, DNOs must ensure that the connected DGs can convey the minimum required energy through the network. Otherwise, DNOs will not be incentivised. Hence, this mechanism could encourage DNOs to be more effective in their investment to accommodate DG connection on their network by considering the

utilization of available DG energy. This new approach has been written in a paper which is currently waiting for publication.

3) This research develops a new approach to set a DSR incentive mechanism, based on the utilization of available DSR energy on the distribution network and its relation with the required investment. The higher the energy from DSR participation, the higher the incentive for the DNOs. DNOs will receive the maximum value of DSR incentive when they can utilize the available DSR energy as required. This means that the value of DSR incentive received by DNOs could encourage DNOs to be more effective in their investment to implement DSR programme on their network by considering the utilization of available DSR energy.
4) This research also develops a new approach to set a mixed DG and DSR incentives mechanism, based on the utilization of available DG and DSR energy on the distribution network and their relation with the required investment. The higher the energy utilization from DG and DSR participation, the higher the incentive for the DNOs. DNOs will receive the maximum value of incentive when they can utilize the available DG and DSR energy in their system. This means that the value of incentives received by DNOs could reflect the effectiveness of DNOs in providing DG connection and implementing DSR programme on the same distribution network, simultaneously.

1.4 OUTLINE

This thesis is organized as follows:

Chapter 1 describes the background, main contribution, objectives, and outline of the thesis

Chapter 2 consists of a comprehensive literature review of Distributed Generation and Demand Side Response, including the reasons to move forwards the low carbon transition, definition and characterization of DG, current installed DG capacity, barriers and the mitigation measures for DG and DSR. This chapter also describes the requirement of incentives for DNOs to facilitate DG connection and DSR implementation. Furthermore, the current DG incentive and DSR incentive mechanisms which are applied in different countries, including Australia, USA and the UK are explained.

Chapter 3 describes the assessment of DG connection and DSR implementation on distribution network performances, in terms of voltage level, power losses and network capacity utilization. This chapter provides a simulation network to observe the impact of connecting new DGs to the existing busbar, both at generation-dominated area and at demand-dominated area. The simulation network is also used to observe the impact of DSR on distribution network, through demand reduction, demand shifting and running on-site generation.

Chapter 4 provides a new scheme to form Energy-based DG Incentives for Distribution Network Operators. This chapter explains the principles, the structure and the methodology used to develop energy-based DG incentives mechanism. The proposed mechanism which considers the type of DG technology, the location of DG connection and the network configuration is examined in case studies.

Chapter 5 provides a new scheme to form Energy-based DSR Incentives for Distribution Network Operators. This chapter explains the principles, the structure and the methodology used to develop energy-based DSR incentives mechanism. Case studies are provided to examine the proposed mechanism.

Chapter 6 describes the analysis of mixed DG and DSR implementation on a particular network configuration. This chapter also develops and explains the principles, the structure and the methodology used to form energy-based incentive mechanism for this mixed implementation. The explanation is complemented with case study.

Chapter 7 concludes the thesis and provides future research work.

2 DEVELOPMENT OF DISTRIBUTED GENERATION AND DEMAND SIDE RESPONSE

2.1 MOVING TOWARDS THE LOW CARBON TRANSITION

In order to tackle the impact of climate change, the government or the energy regulators need to provide supporting regulations to move towards the low carbon transition. Some countries have set a target to substantially reduce their carbon emissions, which come from many sources including electricity sector. In electricity generation and supply process, the reduction of carbon emission can be gained by increasing the number of distributed generation (DG) and implementing demand side response (DSR) on distribution network.

The presence of distributed generation (DGs) to generate electricity can reduce carbon emissions as well as increase the penetration of renewable resources because, mostly, they use renewable energy sources to produce electricity. However, the presence of renewable DGs might require more reserve generations to anticipate the supply scarcity due to those DGs are out of service. The reserve generations consist of generations with quick start-up, of which, they are usually fossil fuelled generations. If this is the case, the presence of renewable DGs could increase carbon emissions emitted from the reserve generations.

While the implementation of DSR through demand reduction and demand shifting mechanisms, can also contribute in reducing carbon emissions. These mechanisms are allowing more efficient use of existing electricity generation and minimising the use of less efficient generations which come from fossil fuelled power plants[13][14].

Since DGs connection and DSR implementation are applied on electricity distribution network, the role of distribution network operators in both mechanisms is vital. DNOs are responsible in operating, maintaining and developing the distribution networks in order to deal with the growth of electricity demand within their working area. The development of DGs and DSR on electricity distribution network and the role of distribution network operators (DNOs) are explained in the following sections.

2.2 DEVELOPMENT OF DISTRIBUTED GENERATION

2.2.1 Definition and Characterization of Distributed Generation

A. Definition of Distributed Generation (DG)

Distributed Generation (DG) or Embedded Generation is defined as any kind of electricity generation which is directly connected to the distribution network rather than transmission network, and the electricity generated, is being used locally rather than distributed to a wider area. Technically, this definition also includes some large power stations, such as Combined Cycle Gas Turbines (CCGTs) and Combined Heat and Power (CHP) technologies of any scales, and can be installed by individuals, businesses, communities and schools [27].

Current technologies of distributed generation which are used worldwide include wind, tidal, wave, hydro, solar PV, geothermal, biomass and combined heat and power (CHP) technologies [12]. These technologies convert the energy sources, which are mostly renewable, directly into electricity. The only technology which might not use renewable sources is CHP, which uses fossil fuels to generate electricity. However, it can be set to be more efficient by capturing and using the heat, as a by-product of electricity generation.

Other types of DG technologies are called micro-generations, defined as generations at a micro-scale which are located decentralized in power system in community's scale [28]. In terms of electricity, the capacity of micro electricity generation technologies is up to 50kW, including solar PV, micro-wind turbines, micro-hydro and micro-CHP [28].

Solar photovoltaic (PV), generates electricity from daylight (not just direct sunlight), and usually installed on Panels, often roof-mounted. Micro-wind (<100kW), uses small wind turbines to generate electricity, can now be roof-mounted as well as attached to. Micro-hydro captures the power of flowing water and converts it to electricity. Micro/domestic CHP and CHP up to 1MWe, produces electricity and captures the waste heat produced as a by-product. CHP used on this scale tends to be for heat and power for a single house or on a community or commercial scale (i.e. a housing estate, or an office block).

B. Characterization of Distributed Generation (DG)

The types of DG technology can be characterized based on three parameters, including capacity factor, levelised cost of energy generation and operational time [29]. These parameters will impact on the calculation of energy output from a particular DG.

1). DG Capacity Factor

DG Capacity Factor is the comparison between actual DG energy output for a period of time and its full rated energy for the same period [30]. This factor directly indicates the ability of DG to deliver energy at its rate and indirectly indicates the supply reliability. Table 2.1 shows various value of DG Capacity Factor from different DG technologies.

Type of Generation	Capacity Factor
Onshore wind	0.350
Offshore wind	0.430
Hydro (run of river)	0.400
Hydro (reservoir)	0.400
Solar PV	0.097
Geothermal	0.800
Biomass	0.900
CHP	0.675

Table 2.1 Generation Capacity Factor [30][31]

2). Levelised cost of energy generation (LCOEG)

The Levelised cost of energy generation (LCOEG) is described as the ratio of all associated costs to generate energy from a power plant over the lifetime of that particular power plant [33]. The unit of LCOEG, which is expressed in £/MWh, is presented in table 2.2 for each DG technologies.

Technology	LCOEG (£/MWh)	Technology	LCOEG (£/MWh)
Onshore	75	10MW Gas CHP	82.6 – 191.8
Offshore	149	Small GT based CHP	75.5 – 176.0
Hydro	42	CCGT CHP	60.4 – 136.7
Geothermal	132	Small Biomass CHP	122.4 – 172.9
Solar PV	202	Large Biomass CHP	113.6– 160.0

Table 2.2 levelised cost of energy generation [33][34]

3). DG Operational Time

The operational time of a DG is determined by the contract between DG developers and DNO. Referring to the UK electricity market, there are four types of DG contracts can be chosen by DG developers [35], i.e. Base Load Contract, Daytime Contract, Night-time Contract and Load Shape 44 Contract. The division of DG contract types is based on the load shape in the day.

Base Load Contracts generators are eligible for a must-take basis for 24 hours. Generators fall under Daytime Contracts might be operated for 12 hours, from 7am until 7pm. The Night-time Contract generators will also be operated for 12 hours, but during night-time hours, i.e. between 7pm and 7am. While the Load Shape 44 Contract generators will be partly operated on the base load power and partly operated on the daytime.

2.2.2 The Role of Distribution Network Operators (DNOs)

Distribution Network Operators (DNOs) have a main role to operate, maintain and develop electricity distribution network within their working area. Therefore, DNOs are required to accommodate requests for DG connection on their distribution networks.

Figure 2.1 depicts a distribution network with some DGs connected on it. The presence of DGs, which are represented by wind turbines and CHP generation, can change the nature of the power flow on the network. In conventional way, the power will flow in one direction from the distribution network to the demand. Since DGs are connected at demand side, the energy will be delivered from the demand side to the network, so that, the power will flow in bi-directional way, from distribution network to the demand, and vice versa.

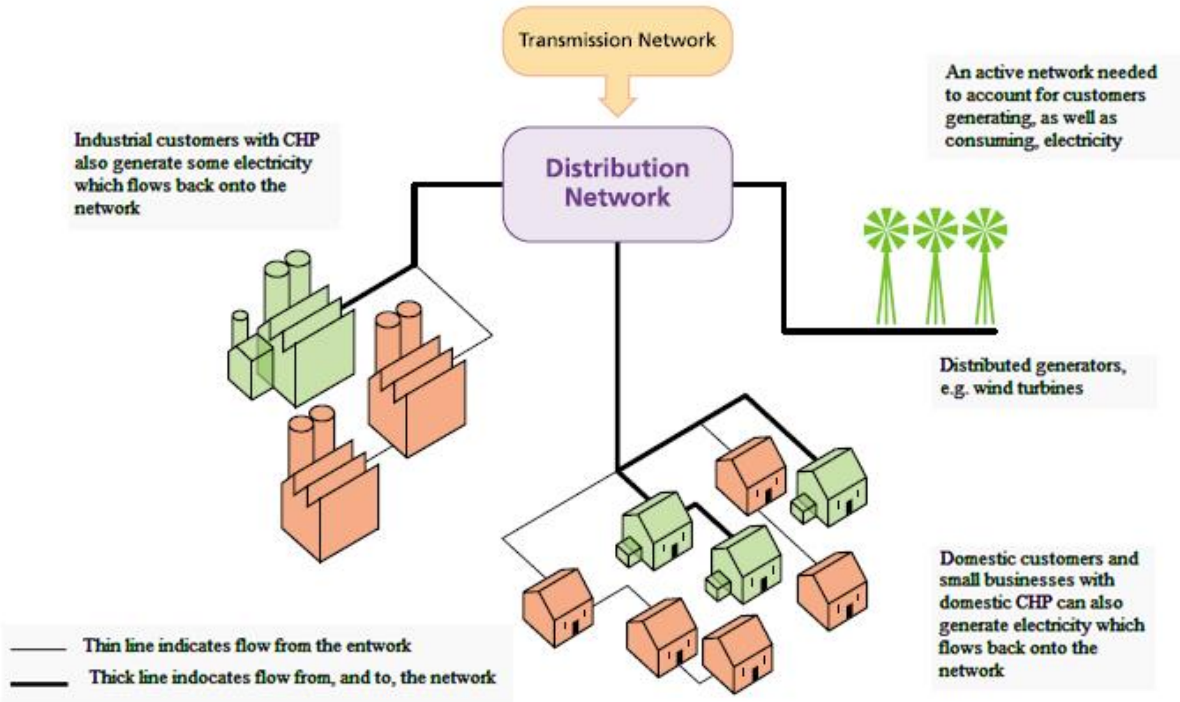

Figure 2.1 Distribution Network with Distributed Generations [9]

Consequently, there will be costs that must be borne by DNOs which are related to installation and connection, as well as routine operational and management fees to operate and maintain them. In order to encourage DNOs to be more active in the development of DGs, the energy regulators need to provide financial incentive mechanisms. Current DG incentive mechanisms are discussed further in section 2.4.

2.2.3 Benefits of Distributed Generation

The development of DG can address the requirement for the energy supply companies to reduce carbon dioxide emissions and to provide secure, clean and affordable energy [27]. The penetration of distributed generation (DG) will also give benefits the consumers or communities.

Since DG is installed near to the demand and the electricity can be directly used by the customers, it will reduce transmission losses. The presence of DG, as an additional electricity supply, will enhance the security of supply for the customers. Another important benefit of DG is related to the environmental impact, i.e. it can contribute in tackling the climate change effects. The use of renewable sources to generate electricity, instead of fossil fuels, will reduce the greenhouse gasses emissions [27].

In terms of customers benefits [27], DG can reduce energy bills and contribute to inhibit energy price rises in the future. Moreover, the installation of DG can attract financial incentives, such as Feed-In Tariffs, for the customers who installed DG and distributed their excess electricity to the grid.

2.2.4 Current Installed DG Capacity

Based on the data taken from Australia, USA and the UK, the penetration of DG in electricity system is quite low. The total installed DG capacity for each country is describe as follows.

Australia has 58.86 GW of installed electricity generation capacity. The generation mix consists of coal 75%, gas 15%, oil 1%, hydro 5%, wind 2%, biofuels & waste 2%, and solar 0.1% [36]. DG contributes 798MW or equal to 1.36% of the total electricity generation. The types of DG technology which are developed in Australia are wind, hydro, biomass, and solar [10].

The total capacity of electricity generation in the United States is around 1,054.8 GW, consisting of natural gas 39%, coal 30%, nuclear 10%, other gases 0.3%, conventional hydro 7%, renewables 6%, petroleum 5%, and pump storage 2% [37]. The types of DG technologies are vary, including fuel cells, turbines, micro turbines, reciprocating engines, wind turbines, photovoltaic, and solar thermal [38] with total capacity of 200 GW, equal to 18.98% of total electricity generation [39].

The United Kingdom, in total, has 93.4 GW of installed electricity generation capacity, including natural gas 46%, coal 29%, nuclear 16%, biofuels & waste 4%, wind 3%, oil 1%, and hydro 1% [40]. The contribution of DG is around 7.01 GW, equal to 7.5% of the total electricity generation capacity. More than 50% of installed DG capacity is dominated by conventional steam stations and CCGT stations, which contributed about 4.647 GW. Another 50% consists of hydro-electric station (natural flow) which contributes 0.133 GW, wind power with 0.484 GW capacity and other renewable sources, include biomass/waste, CHP, solar PV and micro-hydro contribute 1.747 GW capacity [28].

2.2.5 Barriers on the Deployment of Distributed Generation

There are four key elements as barriers for the implementation of DG including costs, lack of reliable information, planning permission and electricity industry issues.

A. Costs Barriers

Higher capital cost and the rewards for exporting electricity, which seems to be small and difficult to access, tend to be the disadvantages for the development of DG [27].

B. Lack of Reliable Information

Lack of reliable information about the deployment of DG, [27] includes the diversity of DG technologies, the available incentives for DG investors that can be accessed and the accreditation scheme for suppliers and installers.

C. Barriers in Getting Planning Permission

Planning permission to install DGs in the community development and new housing is becoming difficult, especially coupled with the associated costs and delays [27].

D. Barriers in Electricity Industry Issues

In terms of electricity industry issues [27], obtaining efficient technological and economical ways to connect DGs to the existing network and the obligation of suppliers to buy excess electricity from small generators tend to be substantial issues that must be addressed.

2.2.6 Mitigation Measures

To deal with the four key elements of barriers in deploying DGs on electricity distribution network, as stated in section 2.2.3, some mitigation measures are taken into account as follows.

A. Mitigation Measures Associated with Costs Barriers

In order to deal with the associated costs in generating and exporting electricity from DG, the electricity regulator might introduce financial incentives, such as the Feed in Tariffs (FITs) mechanism or other financial rewards [27].

Feed in Tariffs (FITs) mechanism is a scheme which allows individuals, communities, organizations and businesses to invest, and in return, to get a guaranteed payment for the electricity they have generated and exported. This mechanism aims to make financial support to households and communities, as well as energy businesses and investors, who engage in small-scale low carbon electricity generation (less than 5MW) [1]. Some countries have applied this mechanism in their electricity markets, including Australia, USA and the UK [38][41][42][43].

Other financial rewards to encourage associated parties to take a part in the deployment of DGs, which are currently applied in some countries, are explained as follows.

In Australia [41], the energy regulators issue an award for the public-recognized leadership in Distributed Energy development, called Public Recognition and Award. They also issue Default Network Support Payments as a standard or default network support payment to be paid by DNOs to DGs for exported electricity to the main grid but, in turn, ensuring that DNOs are not disadvantaged in providing such payments.

In USA, the energy regulator implement Economic Incentives to reduce the economic threshold for some projects development, including wind, PV, biomass, hydro, & fuel cell [38][42].

Meanwhile, the UK's energy regulator set some mechanisms to encourage DG operators increasing the use of renewable energy sources to generate electricity, through Renewable Obligation and Green Energy Certificates.

The Renewable Obligation is a mechanism administered by OFGEM to put obligation on licensed suppliers, to take their sources of electricity and to annually increase the proportion of their sales from renewable sources. Since it was introduced in 2002, it has accelerated the growth of wind generation, especially onshore, with an increase from about 1.3TWh in 2002 to about 5.8TWh in 2008 [43].

Generators, who use renewable energy sources to generate electricity, have the right to claim the Green Energy Certificates [44], including Renewables Obligation Certificate (ROC), Levy Exemption Certificate (LEC) and Renewable Energy Guarantees of Origin (REGO).

- The Renewables Obligation Certificate (ROC) is a certificate issued by the Government, to demonstrate that a generator has supplied a proportion of its electricity from renewable energy sources. One Renewables Obligation Certificate is based on each megawatt hour (MWh) of renewable electricity generated [43]. In addition, generators can sell ROCs to the suppliers [44].

- The Levy Exemption Certificate (LEC) is a certificate for the Climate Change Levy (CCL) exemption, i.e. an environmental tax imposed on the supply of a certain taxable commodity, like electricity, to final business consumers [44]. Generators with renewable energy sources can claim one LEC for each 1MWh electricity generated and they can sell LECs to the utilities or other third parties.
- The Renewable Energy Guarantees of Origin (REGO) is a certificate which demonstrates that generators have used renewable energy sources to generate electricity. One REGO is issued per kilowatt hour (kWh) of renewable electricity generated. Unlike the other two certificates, REGOs do not have monetary value [44].

B. Mitigation Measures Associated with Lack of Reliable Information

Lack of reliable information can be handled by providing all aspects of DG including micro-generations and energy efficiency measures, given by a trusted organisation [27].

C. Mitigation Measures Associated with the Planning Permission

The regulator might introduce regulation to curtail the regulatory burden on existing suppliers and ease new suppliers to participate, such as giving licence-exempt certificate for small generation [27].

D. Mitigation measures associated with electricity industries barriers

Barriers associated with electricity industries can be addressed by establishing discussion and research groups amongst associated parties who collaborate in DG development and enhancing competition level in the new connections provision, both for demand and generation customers. Also, the energy regulator should encourage the distribution network operators (DNOs) to be more active in accommodating DG connection on their network by providing financial incentives for them [27].

Another solution to solve the problem associated with this issue is by deploying an active network management (ANM). ANM can be described as automatic control and coordination of devices and resources to manage the network constraints [20].

The deployment of ANM is driven by some targets that must be achieved in electricity system, including increasing the penetration of renewable and DGs, reducing capital expenditures, maximising the use of assets, and enabling low carbon technologies [20]. An example of ANM scheme is depicted in figure 2.2

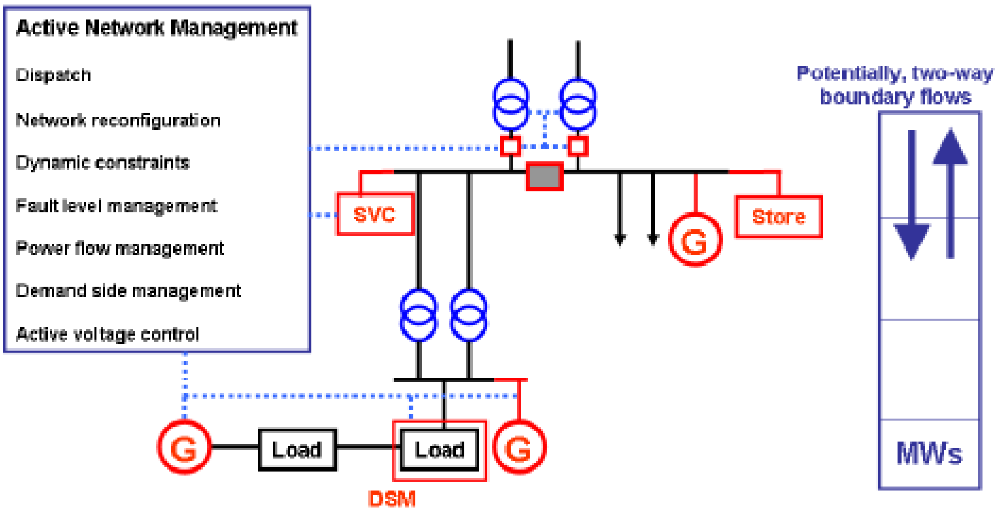

Figure 2.2 Active Network Management [20]

As shown in figure 2.2, active network management can be utilized for dispatching power on the network, reconfiguring the network, dealing with dynamic constraints, fault level management, power flow management, demand side management and active voltage control. Some devices and resources that currently can be controlled by ANM include transformer's tap changers, switching devices, generator's output (active and reactive powers – P and Q) and industrial's demand and system controls [20].

2.3 DEVELOPMENT OF DEMAND SIDE RESPONSE

2.3.1 Definition and Provision of Demand Side Response

A. Definition of Demand Side Response

There are some definitions to describe Demand side response (DSR). DSR in the electricity market is defined as the response acted by electricity consumers to high prices or network congestion [37]. DSR is also described as a deliberate act of end user, either as an individual or a group, to change their demand in response to energy market price or the signals of congested network [15]. Other definitions for Demand Side Response are given by [16], i.e. as an intentional modification of electricity consumption by end-use customers in response to imbalances or market prices; and given by [17], i.e. refers to the customer's response to a signal, either congestion or price signal, by changing the amount of electricity they consume at particular times. In which, one of the benefits from this action is it can provide flexibility in energy system to deal with intermittent generation from renewable sources.

B. Provision of Demand Side Response

The provision of demand side response requires participation from stakeholders, including network operators, suppliers, aggregators and end-users [23].

- Network operators might consist of transmission network operators (TNOs) and distribution network operators (DNOs).
- Suppliers are parties who purchase electricity from generators and sell it to end-users. Sometimes suppliers also own generators, so that, they can sell their electricity directly to end-users.
- Aggregators are responsible in coordinating and combine small DSR contribution from end-users. This aggregated DSR will be offered to suppliers. Then, the suppliers will offer this aggregated DSR contribution to DNOs or TNOs.
- The last stake holder in DSR provision is end-users. End-users, include industries, commerce and households, are connected to the distribution network and consume electricity from suppliers.

There are three mechanisms in DSR of which end-users can participate, include (i) changing their energy consumption pattern by reducing or increasing their electricity consumption; (ii) installing on-site generation; and (iii) shifting their demand at peak times to other hours of the day [15][16][17][25].

The implementation of DSR programme on distribution network can be controlled by two mechanisms [17][25], i.e. automated DSR or direct load control, and end-user controlled DSR. Through automated DSR or direct load control, a contactor or aggregator can remotely turn on and off end-user’s machines. While end-user controlled DSR allows end-users to change their electricity consumption pattern to get incentives, either manually or through pre-programming machines.

In order to support the deployment of DSR in the UK Electricity System, some technologies associated with DSR communication and control have been applied [17], such as the use of radio signals to operate tele switches on night time heaters, the use of timers to equip customer’s appliances using a pre-set programme, deploying smart appliances which can automatically respond the electricity grid congestion or price signals, the use of smart meters to record information related to consumer's energy usage and the use of mobile phone and land lines to transmit prices or commands to change demand, either automatically or by voice. In Australia [45], large industrial users can participate in demand management to reduce their usage of network capacity through engaging with DSR aggregator to participate in scheduled or on-call demand reduction and allowing Distribution Network Service Providers (DNSPs) to exercise direct load control.

2.3.2 The Role of Distribution Network Operators (DNOs)

The role of DNOs in the implementation of DSR programme on distribution network can be explained by referring to figure 2.2. This figure shows an example of DSR programme which is run by one of DNOs in the UK.

Figure 2.3 Demand Side Response Provision: Honeywell I&C ADR Project [46]

At times of peak demand, Scottish and Southern Energy Power distribution, as one of DNOs in the UK, can reduce the electricity consumption on their network by employing Automated Demand Response (ADR) programme [46]. The Demand Response Automation System (DRAS) will send an action signal to the ADR Gateway device which has been installed in each participated building. This signal will initiates Electricity Load Shedding Strategy, which is programmed in each building's Building Management System (BMS), to turn down the pre-agreed electricity apparatus, including air handling units, lights and heat pumps.

In this case, the DNOs must provide more sophisticated network configuration and technology application, such as smart grid, smart meters and required automated software, to implement DSR programme. Consequently, there will be costs that must be borne by DNOs. In order to support and encourage DNOs to be more active in the development of DSR program, the energy regulator should provide financial incentive mechanisms. Further discussion about current DSR incentive mechanism is presented in section 2.4.

2.3.3 Benefits of Demand Side Response

The implementation of DSR on distribution network can give benefits to all parties which are involved in the programme, including the deferment of new network investment, the reduction of supply scarcity, the reduction of electricity prices and the reduction of environmental impact.

1). Benefits associated with the deferment of new network investment

DSR can be used to manage constraints of the network by keeping the amount of electricity demand within the limitation of the grid [17]. If the amount of electricity flowing through the grid is too high, that might cause damages or failures. DSR can temporarily reduce demand to prevent this high electricity flow occurs. In the presence of unexpected failure, DSR can also reduce demand to prevent further damage. If an extreme case of black out occurs, DSR can be used to restart the system through assisting a synchronised start-up of supply and demand. Regular demand reduction at peak times can also reduce the requirement of new investment in distribution network, without any required change in the electricity system management philosophy [17][47]. DSR can lower the risk of the interconnected power system security and improve the asset utilisation across the system due to flattening load profile [19].

The benefits of a large scale DSR to relieve the network constraint at a particular central business district is efficient only when the DSR is well enough aggregated by large users and DNSP has direct control over the load at times of peak demand. If the network constraint can be relieved, consequently the network augmentation can be avoided [18].

2). Benefits associated with preventing supply scarcity

In case where there are some stand-by generators, i.e. generators installed by costumers to deal with emergency/unforeseen events, there might be overlap between operating additional inefficient generation from network operator and running on-site/stand-by generators in order to balance the network’s demand and supply [19]. Therefore, if demand reductions at peak times can be reliably maintained, the required capacity from additional electricity generation can be essentially reduced.

Customers can participate in DSR program by providing the ability to reduce demand quickly in an emergency at short notice. These customers would effectively be on stand-by reserve relates to the need of system balance in emergencies/unforeseen events. Meanwhile, the growth of intermittent electricity generation such as wind will cause balancing mechanism in the system become more difficult. The system will require increased amount of reserves, which can be provided by combining synchronized and stand-by reserves. The synchronised conventional generation must be run part loaded to supply reserve, which leads to inefficiency losses. In order to supply energy which is originally allocated to that part loaded generation, the system will require additional generation capacity. Furthermore, balancing mechanism also requires stand-by reserves which can be supplied by higher fuel cost power plants. In this case, DSR can substitute the role of stand by generation capacity [19].

3). Benefits associated with the reduction of electricity prices

Since demand increases during peak times, additional electricity is required to meet the demand. Sometimes, less efficient generators with high operation cost, perhaps with higher CO_2 emissions, are needed. This high cost will be passed onto the customers. By shifting demand at peak times to outside peak hours, where more efficient generators are available, it will reduce or may avoid the needs to run inefficient generators [19]. Therefore, it can reduce the costs and the emissions of carbon dioxide per kWh electricity.

In electricity market, DSR will make the market becomes more predictable, stable and efficient due to volatility and risks of electricity contract prices and terms can be reduced [17][19]. DSR also impacts on maximising social welfare [18], i.e. when all consumers at a particular area consume electricity to the extent that the value of their consumption exceeds the marginal cost to provide electricity (also called as electricity market Locational Marginal Price, LMP). At the same time, all electricity producers at that area produce electricity to the extent that their production cost is less than LMP. The proper LMPs will also encourage generators whose costs are lower than those LMPs – but higher than pre-existing LMPs to generate electricity. This will increase the amount of generation available. The increasing generation might change the amount of efficient DSR.

DSR might also reduce the price paid for power by load since lower demand will cause lower price [18]. This becomes benefit for the load, at least in the short run. If proper calculation causes the value of LMPs to increase, the price that consumer has to pay for their electricity consumption will be higher. This condition will encourage consumers to participate in DR because in return, they increase their savings by not consuming electricity.

4). Benefits associated with the reduction of environmental impact

The implementation of DSR has significant benefits on environment. These include reducing emissions due to network losses reduction and more efficient use of base load generators and mitigating negative environmental impacts from fossil-fuelled power plants. In terms of electricity generations with finite resources, these also mean reductions in resources consumption which could impact on resources scarcity [17][19].

2.3.4 Current DSR Implementation

A. DSR Implementation in Australia

In Australia, potential DSR from industry is estimated represents about 10.5% of the total 36GW peak load. This consists of 3.1GW identified DSR capacity and 0.6GW estimated DSR capacity registered for 2014-2015 [22]. The data taken from 34 participated companies including mining, manufacturing and others. From the total identified potential DSR capacity, over 95% could be available with 2-4 hours' notice. This trial using capacity market mechanism, in which the DSR providers are paid based on the available capacity at peak time. In 2011, as much as 2,559MW out of 32,538MW total demand (in 2010-2011 period) is estimated to participate in DSR [22].

B. DSR Implementation in USA

DSR trial in USA shows that 60% of the tests have produced reduction in peak demand of 10% or greater [21]. DSR trial was implemented by using time of use rates and smart metering roll-out. This mechanism was deployed in Ontario to incentivise customers for curtailing their electricity consumption during the peak times which can reduce the overall usage of electricity. The roll-out of smart metering is an important step to make transition from fixed price to dynamic pricing [21].

The average number of DR resources registered during summer 2011 was about 6.46 million resources with combined capacity of 50,919MW and 3 hours and 6 minutes of average sustained response period. While during winter period 2011-2012, the average number of registered demand response resources was about 5.34 million resources with combined capacity of 48,686MW and 1 hour and 43 minutes of average sustained response period.

Overall, the potential DR resource contribution in U.S. RTO/ISO increased by 4.1 percent since 2009 [48].

C. DSR Implementation in the UK

There are two potential areas of growth for DSR in the UK, i.e. turn-down DSR and running on-site generation [49]. Turn-down DSR is a mechanism to reduce electricity consumption by consumers during times of peak demand, through turning off their electricity appliances. Meanwhile, running on-site generation means operating generations at consumer's side, which are installed and owned by consumers, at times of supply scarcity on the network.

Currently, households contribute almost 50 % of UK's 56 GW winter peak demand but they make relatively small contribution to DSR. Therefore, the smart meters roll out is expected to make this contribution increases. Furthermore, Time-of-use tariffs which are partly controlled by smart meters have encouraged household to participate in some DSR trials in the UK. This participation could make 10% peak demand reduction. Furthermore, future electrification of heat and transportation such as heat pumps and electric vehicles could be potential household demand suitable for DSR.

Regarding on-site generation, it is predicted that around 1 to 20 GW of on-site generation in industrial and commercial sectors is still unused [49]. This amount of capacity is very potential to be used for DSR. In households and some commercial sectors, the increase number of small-scale gas-fired Combined Heat and Power plants could provide additional capacity suitable for DSR.

Meanwhile, non-domestic sector might have more technical potential to contribute in DSR programme. In 2011, a study [50] suggested that the implementation of DSR can reduce the winter peak demands by 1 to 4.5 GW out of 15GW total demand from non-domestic customers.

2.3.5 Barriers on the Implementation of Demand Side Response

This section describes some barriers in the implementation of DSR, in terms of the parties' participant, the regulation and the use of advance technology.

A. Obstacles Associated with Parties Participant

Currently, DNOs do not have enough encouragement to invest in DSR programme or dynamic pricing projects instead of capital projects [22]. This reason is driven by the fact that the initial cost of setting up DSR, include costs for analysing consumption patterns and costs for installing and operating communication technology, are expensive [26][49]. In contrast, savings from DSR do not provide sufficient financial return because the total shifted demand from individual end-user is too small [49].

Another concern refers to the customer awareness which is quite low. In case of DSR implementation in USA, the number of retail customers on time-based rates is limited [48]. This might be cause by the fact that the interaction between suppliers and end-users (households and commercials) is limited to billing while direct interaction between customers and with DNOs is less. Some trials [49] show that customers who have signed up for end-user controlled DSR do not give certainty about the amount and reliability of committed demand shifting capacity, some even lose interest.

B. Obstacles Associated with Advance Technologies

Advance technologies including smart meters and smart appliances have important roles in implementing DSR. Some identified barriers related to advance technologies are lack of consistency in the measurement and verification of demand reductions and lack of Demand Response Forecasting and Estimation Tools [48].

Data privacy and cyber security [49] become crucial issues to be addressed related to the deployment of smart meters because data from household and commercial customers become accessible from outside. Other concerns include misuse for commercial purpose, data theft and terrorist threat of cutting electricity to users.

Moreover, most of industrial businesses are not ready to provide the required capabilities, skills and technology for DSR and DSR may be not the top priority for industrial businesses.

C. Obstacles Associated with Regulation

In USA, the traditional utility regulation hinders investment in demand response (DR) and energy efficiency (EE) [26]. Traditional utility regulation provides opportunities for utilities to earn a rate of return on infrastructure investments in generation, transmission and distribution. Hence, if there are two equivalent alternatives for the utilities of building a profitable power plant or investing in DR and EE for cost-recovery only, a utility generally will opt the first alternative, i.e. building a power plant. Furthermore, traditional utility regulation set the revenue of a utility based on kilowatt-hours sales of electricity. The more customers consume electricity, the more revenue the utility can earn. This regulation will discourage utilities to implement DR and EE on their system since both mechanisms will reduce electricity consumption by customers, even in cases where utilities can recover the investment costs. There is also lack of coordination among policies at the federal and state levels [48].

Considering the implementation of DSR in the UK, inefficient use of DSR can be caused by infrequent utilisation of DSR providers. Moreover, due to contractual conditions, a DSR provider cannot be contracted by more than one stakeholder. However, since the usage patterns of different parties, such as National Grid and a DNO, are different and there is no significant interference amongst them, stakeholders suggested a possibility for a DSR provider to be contracted by multiple parties [49].

2.3.6 Mitigation Measures

In order to mitigate the obstacles that might be occur in the implementation of DSR programme, some measures are taken into account as described as follows.

1). Mitigation Measures Related to the Low Participation of Associated Parties

In order to encourage DNOs to invest in DSR programme or dynamic pricing projects, the energy regulator should establish mechanisms to give financial incentives to the DNOs. Current DSR incentive mechanisms are explained section 2.4.

Regarding the customer participation which is quite low, suppliers are required to deliver full price signals [23]. It is expected that the customers will change their electricity consumption pattern to reduce their bills, i.e. by not consuming electricity at peak times. The change of consumers' behaviour in electricity use can reduce the electricity prices, as well as reduce the peak demand.

Encouraging consumers to change their behaviour in electricity use, which also means to change of their lifestyle, requires an appropriate level of financial incentive. Offering reasonable tariffs to save consumer's money and introducing automated devices to response the price signals tend to be an effective way to change consumers' behaviour [14]. Incentives can be given through offering different tariffs to consumers, such as by distinguishing the electricity prices at peak and off-peak demand. The off-peak demand has lower prices, so the customers will be financially incentivised for reducing their electricity consumption at peak demand. However, for some customers, the difference in electricity prices will not tempt them to change their lifestyle. They prefer to spend more money to maintain their comfort. To deal with this situation, customers' willingness in changing their electricity consumption has an important role.

Incentives for customers can also be given through DSR compensation mechanisms, such as Dynamic Pricing and Contracts, Locational Marginal Price, Fixed Price and Fixed Prices Consisting of Generation and Non-Generation Components [18].

Dynamic pricing [18] is a pricing system for the electricity which reflect the relevant real-time a day-ahead LMP. The price is used to charge for the electricity consumption or to pay the electricity purchase. Customers who are participating in the spot market pay the LMP for the electricity they consumed. However, they may sign a contract for a fixed price of a given quantity of electricity.

Through locational marginal price scheme [18], generators which are connected to distribution network (DGs) will receive payment based on their locations and the amount of electricity they generate each hour. Hence, they will receive an incentive if they can produce electricity at a lower cost than LMP. The consumers who do not consume at those hours will save the LMP. So, they have an incentive to consume whenever the value of electricity is higher than LMP.

Fixed price scheme [18] can be explained using the following example. A customer has a contract for a given quantity of electricity at its place for a fixed price C. Suppose that a given point in time, the LMP at customer's location exceeds the marginal value that customer put on the electricity MV. In this case, it will be more efficient for the sell the electricity to the market rather than to consume it. When the LMP at customer's location is less than MV, consuming electricity at that given point of time is more efficient for the customers.

Fixed prices consisting of generation and non-generation components scheme means that the fixed price F consists of three parts, i.e. a generation component G, a transmission component T, and a distribution component D. If LMP is greater than the marginal value of electricity, the customer has an incentive for not consuming the electricity. Since F is greater than G, LMP-G is greater than LMP-F. If a payment of LMP-F can encourage customers not to consume electricity at inefficient time, a larger payment will be more sufficient to encourage the customer to behave in that manner.

Since participation of a single customer has a very low contribution to the amount of demand reduction, and usually will be neglected, the regulator should determine cumulative benchmarks which match against signal responses [22]. It is also important to maintain appropriate performance and compensation for DSR contributions through accurate measurement using established baselines [25].

In 2013, Energy Act introduced capacity market mechanism to guarantee sufficient reliable capacity in the UK electricity system. This mechanism offers payment for commitment to deliver electricity or temporarily reduce demand when required. Payments for committed capacity will be offered to companies via auctions. The payments for DSR participation will be available from 2015 while generation will be eligible for payment for generating electricity from 2018 [49]. The capacity market mechanism is also applied in Australia's electricity market. Through this mechanism, the DSR providers are paid based on the available DSR capacity at peak time. This mechanism is applied by the Wholesale Electricity Market (WEM), which is operating in the South-West Interconnected System (SWIS) in Western Australia [22].

2). Mitigation Measures Related to Advance Technologies

To deal with the needs of advance technologies in implementing DSR, some actions could be taken into account, such as installing common protocol for data communication amongst different meters and other technology [22], developing advance technologies to integrate new forms of DSR into normal system operations during peak and off-peak times [25], providing accurate and timely information about overall performance of electricity system and operations of specific DSR by deploying adequate equipment for metering and communication [25] and another idea is implementing remote devices via smart meters that will allow suppliers to automatically reduce demand as a response to price signals [22].

There should be accessible, accurate, understandable, and comparable information for consumers to take an active role in the development of DSR, especially in terms of electricity prices. The information should cover electricity prices comparison for all consumers, including vulnerable and low-income consumers, who may be most attracted to the cost savings [14].

Facilitating DSR in distribution networks requires advance technologies, to make the process run automatically. The technologies must have capabilities on detecting load curtailment requirement, delivering the requirement to participating users, curtailing or shedding the load automatically, and verifying the demand response compliance.

The roll-out of smart meters, which will be conducted in the UK between 2015 and 2020 [49], is one solution that can be applied to deal with the problem related to advance technology. The aim of this policy is that smart meters can develop interactive communication between suppliers and customers. Hence, households are expected to be much easier to provide and participate on DSR.

Another solution related to advance technologies is by deploying an active network management (ANM), as shown in figure 2.2. This scheme can be used to automatically control and coordinate the network's devices and resources, as well as to automatically manage the network constraints. In demand side, this scheme can be applied to control electric vehicles (EVs), energy storages and other domestic appliances in response to congested network [20]. Another definition of ANM is given by [51] as a smart way to operate the electricity network without solely relying on network's infrastructure investment.

3). Mitigation Measures Related to Regulation

According to [52], there are three parameters that must be taken into account to arrange the service incentive mechanism, i.e. the size of the service incentive, the differentiation of the incentive including regions and customer types, and the possibility to pass through the liability that DNSPs may suffer under a service incentive scheme to a DSR proponent.

Given DSR solutions are less reliable that network solutions, the size of the service incentive will impact the DNSP decision on comparing DSR or DG project with network augmentation project. The basic principle of the service incentive is that the reward or penalty scheme might encourage DNSPs to opt DSR or DG solutions which will benefit customer.

The differentiation of the incentives should consider the improvement of service in prioritising customers with poorer reliability, such as customers in remote areas served by a long feeder, at a higher value place. It means that the higher reward related to that improvement should be provided. This mechanism is expected to encourage DNSPs to improve their service at poorer reliability areas.

Relevant factors that should be taken into account in the incidence of penalties and rewards include the ability of DNSPs to reward for service incentive outcomes to DSR providers, the readiness of DSR providers to bear the risk and the willingness of potential customers to voluntarily give up their right to guaranteed service level payments associated with non-network solutions trials.

Furthermore, the role of DNOs should be extended, i.e. to be more active distribution system operators rather than relatively passive and non-innovative, so that in the future, DNOs and National Grid can work together much more closely [23]. Also, in order to get substantial benefits from DSR programs, the desired benefits must be appropriately defined and the payments must be properly structured. Proper payments structure will follow the benchmark of dynamic pricing and explicit contracts [18].

2.4 CURRENT INCENTIVES MECHANISMS FOR DISTRIBUTION NETWORK OPERATORS (DNOs)

As previously described, DNOs are responsible to operate, maintain and develop electricity distribution network within their working area. This role becomes more complex with the presence of DG and the implementation of DSR programme on distribution network.

DNOs must provide more sophisticated network configuration and technology application, such as smart grid, smart meters and required automated software, to accommodate DG and DSR in their system. As a consequence, there will be costs that must be borne by DNOs which are related to meters installation and software purchase, as well as routine operational and management fees to operate and maintain them. Therefore, electricity regulators should encourage DNOs to be more active in the development of DGs and DSR on their network by providing financial incentive mechanisms.

The following sections describe current incentive mechanisms related to DG connection and DSR implementation which are currently applied in some countries, including Australia, USA and the UK.

2.4.1 Current DG Incentive Mechanisms for DNOs

DG incentive mechanism which is currently applied in the UK, aims to encourage DNOs to connect distributed generation by providing incentives for necessary investment. Referring to the Regulatory Instructions and Guidance - Version 2, April 2007 [53], there are two main purposes of DG incentive mechanism, i.e. encourage DG connection on the distribution network and reduce regulatory barriers for DG connection.

The first purpose, i.e. encouraging DNOs to proactively respond to requests for DG connection, aims to attract more DGs to be connected to their network. This effort is aimed to achieve the UK renewable targets in 2020. In line with the connection request, DNOs must provide efficient and economical investment.

The second purpose, i.e. ensuring that there will be no regulatory barriers for DG connection request, even if the proposed connected capacity or the cost exceeding the forecast. This mechanism will protect both DNOs and customers. DNOs will get certainty to deal with unpredicted cost increment for DG connections. While the customer will not have to pay more for their usage, due to the increment of DG connection cost that must be borne by DNOs.

A. Cost Elements of DG Connection

Figure 2.4 shows the cost elements of DG connection assets [54]. Every DG connection costs will be recovered through two types of charges, i.e. connection charges and use of system charges. The calculation of DG incentive and pass-through is based on the use of system connection assets cost only, which is being recovered via use of system charges. This means that if a DG connection does not require use of system connection assets, there is no incentive related to this connected DG.

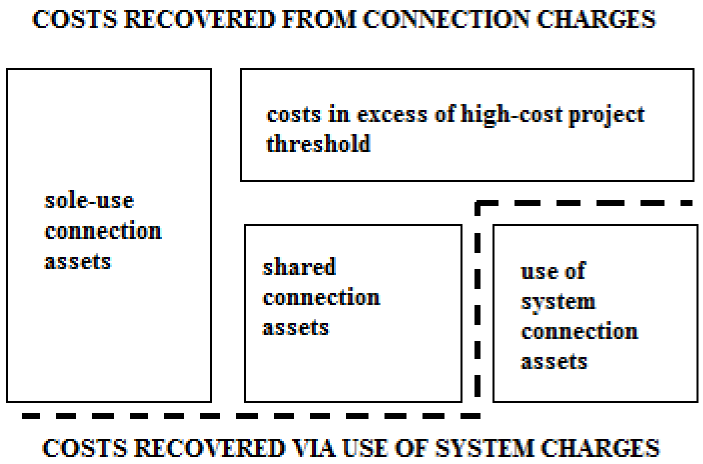

Figure 2.4 Cost Elements of DG Connection Assets [54]

B. Structure of Current DG Incentive

The structure of current DG Incentive comprises of two hybrid elements, i.e. the pass-through mechanism and an additional DG Incentive value [54]. Pass-through mechanism is a mechanism to give the DNO a partial percentage pass-through treatment of the reinforcement costs incurred in providing network access to DG, to be passed on the customers who seek for the connection. While additional DG incentive value is calculated based on the capacity of the connected DG, expressed in £/kW/year. This framework is annuitized over the assumed life of DG connection assets, which is 15 years after the connection date. Since the incentive is given based on the capacity of connected DG, this mechanism can also be referred to as capacity-based DG incentive mechanism.

1). Level of Pass-through

In order to encourage DNOs to be more proactive in the deployment of DG connection and to deal with the higher variability associated with DG connection, the UK's Office of Gas and Electricity Markets (OFGEM) provided a slightly higher pass-through and lower strength of incentives for the DNOs to recover their costs associated with DG connection [55].

Based on the OFGEM's modelling, 70% pass-through will give a minimum guaranteed real return of 1.4% to the DNOs on any individual project. While 80% pass-through is equivalent to 3.2% minimum real return. Given the lower real return might cause DNOs to delay major strategic reinforcement project, OFGEM adopts 80% pass-through rate for the DG incentive scheme [55].

2). Current DG Incentive Rate

According to Anna Rossington from OFGEM [56], the capacity-based DG incentive can be calculated as follows:

Parameters	**Calculations**	**Results**
Average connection cost /kW		£34.00
pass through rate		80.0%
pass through revenue /kW	= £34 x 80%	£27.20
additional return		1.0%
pre-tax WACC		5.6%
desired return	= 1% + 5.6%	6.6%
combined revenue /kW given desired return	= £34 + 6.6% x £34	£36.24
Incentive rate required /kW	= £36.244 - £27.2	£9.04
Years (nper)		15
Annual Incentive Rate /kW/year	= PMT(5.6%, 15, -£9.04)	£0.91

Table 2.3 Parameters of Capacity-Based DG Incentives [56]

In the Distribution Price Control Review 5 (DPCR 5) [24], which is running from 1 April 2010 until 31 March 2015, the cost of use of system connection assets is set at £34/kW. 80% of this cost, i.e. £27.20, will be passed on to the customer who seeks for connection.

As shown in table 2.5, the Office of Gas and Electricity Markets (OFGEM – the UK's energy regulator) has set a pre-tax Weighted Average of Cost of Capital (WACC) of 5.6% plus an additional rate of return of 1%. These two rates will result in a desired rate of return for DNOs of 6.6%.

By multiplying the desired rate of return with the average connection cost, then subtracts the result with 80% pass-through will give an incentive rate required as:

= £34 x (1+ 6.6%-80%) = £9.04 /kW

Considering the value of incentive rate required, the WACC, the additional rate of return and the interval period, the annual DG incentive rate can be obtained from:

$$= \frac{\text{Incentive rate required} * (1+\text{WACC}+\text{additional return}-\text{passthrough}) * \text{WACC}}{(1-(1+\text{WACC}))^{-\text{nper}}} \quad \ldots (2.1)$$

$$= \frac{9{,}04 * (1+0.056+0.01-0.8) * 0.056}{(1-(1+0.056))^{-15}} = £0.91/\text{kW}$$

Then, the value of the DG incentive rate, which is £0.91/kW, is rounded to £1/kW/year.

3). The Maximum and Minimum Thresholds on DNOs Returns

The maximum (cap) and minimum (collar) thresholds on DNO returns are aimed to protect the DNO as well as the customers against cost uncertainty [54]. The minimum rate of return is set equal to the assumed cost of debt, i.e. 3.6% pre-tax, and the maximum rate of return is set equal to two times the pre-tax WACC, i.e. 11.2%. The WACC stands for Weighted Average Cost of Capital, i.e. the average rate of return that a company is expected to pay to all its creditors, owners, and other providers of capital, based on its existing assets [56].

4). High Costs Projects

High cost project are defines as projects which require significantly high cost in excess of the DNO's standard. OFGEM allows DNOs to undertake projects with maximum direct reinforcement cost of £200/kW [54].

2.4.2 Current DSR Incentive Mechanisms for DNOs

A. Costs of Demand Side Response

As presented in table 2.4, there are two cost categories for DSR implementation, i.e. participant cost and system costs [17][49]. Participant costs, i.e. the costs that will be directly passed onto the customers who participating in DSR programme, include costs for technology (for smart meters and smart appliances), response plan, comfort/inconvenience, reduced amenity/lost business, and onsite generator fuel and maintenance. While systems costs include all costs associated with metering/communication system upgrade (system settlement), utility equipment/software, consumer education, program administration, marketing, payments for participating customers (billing and tariffs), and programme evaluation.

Type of cost		Cost
Participant costs	Initial costs	Enabling technology investment
		Establishing response plan or strategy
	Even specific costs	Comfort/inconvenience costs
		Reduce amenity/loss business
		Rescheduling costs (e.g. overtime pay)
		On-site generator fuel and maintenance costs
System costs	Initial costs	Metering/communication system upgrades
		Utility equipment of software costs, billing system upgrades
		Consumer education
	Ongoing programme costs	Programme administration/management
		Marketing/recruitment
		Payments to participating customers
		Programme evaluation
		Metering/communication

Table 2.4 Costs of DSR Implementation [17]

However, the DSR establishment cost is unique to each situation. It depends on the nature of the DSR programme its self, including its reliability, availability and duration [57]. In case of a DSR trial in the UK [58], customers who involved in DSR will be compensated for any costs related to inconvenience, lost business, fuel and other expenses. Then, the DNOs wrap these costs up into a single price, as the cost of DSR. The DNOs are also responsible in covering the cost of software, billing systems, education etc.

B. Implemented DSR Incentives Mechanisms

The following sections describe current incentive mechanisms for DSR implementation in some countries, including Australia, USA and the UK.

1). DSR Incentives for DNOs in Australia

The New South Wales Independent Pricing and Regulatory Tribunal (IPART), one of Australian jurisdictional regulators, has implemented a demand management incentive mechanism called ‘D-factor’ [25]. This mechanism acts as an additional incentive for Distribution Network Service Providers (DNSPs) to recover the costs and forgone revenues associated with DSR initiatives and effectively allows these costs to be passed through into higher prices with a maximum value equivalent to the expected avoided distribution costs.

2). DSR Incentives for DNOs in United States of America

In terms of incentive mechanisms, some forms of incentives that have been trialled in USA, include Shared Savings, Rate of Return and Avoided Cost [26].

Shared Savings allows utilities to receive a percentage share of the energy saving as a result of Demand Response (DR) or Energy Efficiency (EE) program. When a utility can increase their participation or saving levels, they will receive higher shared savings percentage. This mechanism will promote cost-effective DR and EE as well as encourage better cost management since ineffective spending might reduce the incentives available. This mechanism has been trialled in Minnesota.

Under rate of return approach, a utility has an opportunity to earn profit on DR and EE investment, based on the utility's rate base, in the same manner as other capital investments. This will encourage utilities to optimise their planning on supply and demand resources. This approach has been implemented in Nevada.

Avoided cost mechanism will give a utility a percentage of their avoided supply costs as their DR and EE savings compensation. This approach has been proposed by Duke Energy Carolina, known as Save-A-Watt. This program allowed utility, who can produce save-a-watts, to recover the amortization of and a return on 90 percent of the avoided costs.

3). DSR Incentives for DNOs in the United Kingdom

The Office of Gas and Electricity Market (OFGEM), as the UK's energy regulator, encourages DNOs to facilitate DSR by establishing the Low Carbon Networks (LCN) Fund scheme [47]. The scheme allows DNOs to try out new technologies, such as smart meters and smart appliances, or commercial arrangements to ahead a low carbon electricity system, in terms of security of supply at value for money.

DNOs can collaborate with other parties in conducting DSR trials on their network. Some DSR trials projects [47], which are funded by Low Carbon Network Fund, include Low Carbon London, Customer Led Network Revolution (CLNR), Capacity to Customers (C2C), Demonstrating the Functionality of Automated Demand Response ADR and New Thames Valley Vision.

Low Carbon London [57] is a series of DSR trials project to examine the effects of energy efficiency schemes and time of use tariffs on industrial and commercial customers. This project also implemented active network management (ANM) which aims to automatically manage network constraints. The trials are run between January 2011 and December 2014 and are operated by UK Power Networks.

Customer Led Network Revolution (CLNR) [58], which is operated by Northern Power Grid, aims to address the potential for new network technology and flexible customer response to a head the low carbon network. The project is carried out from September 2010 until December 2014.

Capacity to customer (C2C) project was carried out by Electricity North West [59]. This project began in January 2012 and completed in December 2014. The aim of this project is releasing the redundant assets of high voltage network and offering customers to provide a post-fault DSR. The project offers customers a reduction in distribution charges in return for agreeing to a delayed power restoration following an outage. Typically, after an outage, power must be restored within one hour but C2C customers can be delayed up to eight hours and the participated customers will be directly connected to high voltage network.

Demonstrating the Functionality of Automated Demand Response (ADR) is a DSR trial project operated by Scottish and Southern Energy Power Distribution [46][62]. This project aims to demonstrate the use of Automated Demand Response (ADR) technology at commercial buildings in load reduction at times of peak demand. The project is carried out from June to November 2011.

New Thames Valley Vision, which is also operated by Scottish & Southern Energy Power Distribution, aims to manage the existing network more intelligently to move towards low carbon technologies. The project is carried out by running a mixture of analytic, technological and commercial solutions, and is built on a successful previous Automated Demand Response (ADR) project. The period of the project is five years, started in 2012 [63][64].

2.5 CHAPTER SUMMARY

The presence of DGs and DSR programme on the distribution network has an impact in reducing greenhouse gasses emissions and increasing the penetration of renewable energy sources in electricity production. Therefore, countries around the world are trying to enhance the deployment of DGs and the implementation of DSR programme in their electricity distribution networks.

Currently, the contribution of DGs and the participation of associated parties in DSR programme are quite low. Considering this condition, some countries, including Australia, USA and the UK, have introduced policies and incentive mechanisms to support the development of DGs and DSR programmes.

The obstacles and mitigation measures related to the development of DGs and DSR programmes, including current policies and incentives mechanism are summarised in table 2.5.

Objective	Obstacles	Mitigation Measures
DGs Deployment	Payment warranty for exported electricity	- Feed in Tariffs mechanism (Australia, USA and UK) - Default Network Support Payments (Australia)
	Lack of reliable information	Providing information for all aspects of DG
	Planning permission	Licence-exempt certificate for small generation
	Electricity industry issues	- Establishing discussion and research groups - Public Recognition and Award (Australia) - Renewable Obligation and Green Energy Certificates (UK)
	Incentives for DNOs	- DG Incentive mechanism (UK)
DSR Implementation	Low Participant	- Different tariffs for peak and off-peak times - DSR compensation mechanisms (USA) - Capacity Market mechanism (Australia and UK) - Aggregate the DSR participation (Australia and UK)
	Use of Advance Technologies	- Smart meters roll-out (Australia, USA and UK)
	Regulation	- Reward and penalty scheme (Australia) - Dynamic pricing (UK)
	Incentives for DNOs	- Demand Management incentive mechanism (Australia) - Shared Savings, Rate of Return and Avoided Cost (USA) - Low Carbon Network Fund (UK)

Table 2.5 Obstacles and Mitigation Measures for DG Connection and DSR Implementation

3 IMPACT OF DISTRIBUTED GENERATION CONNECTION AND DEMAND SIDE RESPONSE ON DISTRIBUTION NETWORK

The existing electricity distribution networks are conventionally developed to meet the requirement to deliver power in one direction, from generation units to end users. The presence of distributed generation (DG) causes the change of the power flow pattern on the distribution network. The power, which conventionally flows in one directional way from the distribution network to the customers, will flow in two directional ways, i.e. from the distribution network to the customers' side and from the customers' side to the distribution network [65].

A number of studies and researches have been done to investigate the effect of DG on the distribution network, including the impact of DG on power quality, reliability, and control of the utility system of the distribution network [8], the impact of DG on the protection of distribution networks [66], the impact of DG on voltage levels in radial distribution systems [67] and the effects of DG penetration on energy losses minimization [6][68][69].

In terms of demand side response (DSR), this mechanism can be used to reduce peak demand. DSR can also be used to respond the requirement to balance the system due to the demand is greater than the supply, by running on-site generation [19].

Some projects have examined the impact of implementing demand side management in association with the deployment of DG connection. One of the projects [80] shows that DSM can maintain the balance between supply and demand. At times when the supply is abundant, for instance there is a lot of wind energy but the consumption of electricity is low, the system will allow customers' devices to store energy. While at times of supply scarcity, the system will allow customers to reduce their electricity consumption.

This chapter describes the impact of DG connection and DSR implementation on the performance of a distribution network, in terms of voltage level, network capacity utilization, and power losses.

A. Voltage Level

The distribution network is designed for delivering electricity from transmission network to the demand side. In the presence of distributed generation (DG), it is used to transfer electricity generated by DGs to the load centres. The voltage levels for distribution network vary amongst different countries. In the UK, distribution networks cover from low to high voltage levels, i.e. 230/400V, 11kV, 33kV, 66kV and 132kV [70]. In Australia, the distribution networks operate at voltage levels of 230/400V, 11kV, 22kV and 33kV [71]. Meanwhile, in United States, the voltage levels for distribution network are in the range between 120/240V and 34.5kV [72].

The impact of DG connection on the voltage level of a distribution network can be investigated through iterative power flow equations used in the Newton-Raphson algorithm [73] as:

$$\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} = \begin{bmatrix} J_1 & J_2 \\ J_3 & J_4 \end{bmatrix} \begin{bmatrix} \Delta\delta \\ \Delta|V| \end{bmatrix} \qquad \text{... (3.1)}$$

Where, ΔP and ΔQ represent the changes of real and reactive power injections at a particular bus, $\Delta\delta$ and $\Delta|V$ represent the changes of bus voltage angles and magnitudes, and J1, J2, J3 and J4 are the elements of Jacobian matrix.

Then, the changes of bus voltage angles and magnitudes can be calculated by inversing the matrix equation in (3.1), as:

$$\begin{bmatrix} \Delta\delta \\ \Delta|V| \end{bmatrix} = \begin{bmatrix} JB_1 & JB_2 \\ JB_3 & JB_4 \end{bmatrix} \begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} \qquad \text{... (3.2)}$$

Where, JB1, JB2, JB3 and JB4 are the elements of the inverse of the Jacobian matrix.

B. Network Capacity Utilization

The term network utilisation is used to explain the capacity of a particular network that has been utilised by network's users, either by DGs or by loads. The unit of network utilisation is expressed in percentage (%), i.e. derived from [74]:

$$\text{Network Capacity Utilization (\%)} = \frac{\text{Network}_{\text{power flow}}}{\text{Network}_{\text{capacity rate}}} \text{x}100\% \qquad \text{... (3.3)}$$

Where, $\text{Network}_{\text{power Flow}}$ represents the line's power flow and $\text{Network}_{\text{apacity rate}}$ represents the capacity rate of the line.

C. Power Losses

Power losses are defined as the amount of power which is lost during power distribution process on the network. Simply, power losses are equal to power generated by at generation sites less power consumed at demand sites.

Referring to figure 3.1, power losses between bus (k) and bus (k+1) can be calculated by using the following equation [67]:

$$P_{Loss}(k, k+1) = R_k . \frac{(P_k^2+Q_k^2)}{|V_k|^2} \quad \ldots (3.4)$$

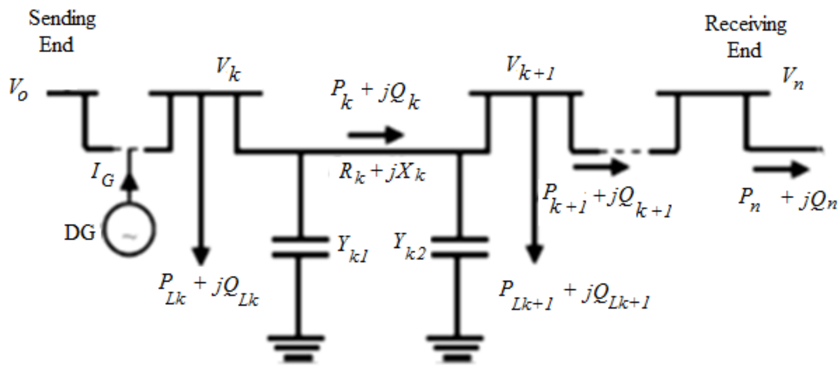

Figure 3.1 Distribution system with DG installation [67]

While the total power losses of the feeder ($P_{T,Loss}$) can be derived by summing up all the line sections losses as [67]:

$$P_{T,Loss} = \sum_{k=1}^{n} P\_Loss\ (k, k+1) \quad \ldots (3.5)$$

3.1 IMPACT OF DG CONNECTION ON NETWORK PERFORMANCE

For the purpose of investigating the impact of DG connection on the performance of a distribution network, including voltage level, network capacity utilization and power losses, the assessment is carried out by connecting a new DG to a generation-dominated busbar and a demand-dominated busbar.

3.1.1 Reference Network

For the purpose of investigating of the impact of DG connection on a particular busbar, the assessment is conducted by using a reference network, as shown in figure 3.2. The network configuration is modelled and depicted using the Integrated Power System Analysis (IPSA) software version 1.6.9.

A. Reference Network

The reference network consists of fifteen busbars with voltage levels range from 275kV down to 0.4kV. There are one 275kV busbar, four 33kV busbars, eight 11kV bus bars and one

0.4kV bus bar. At 11kV voltage level, there are two generation-dominated busbars, i.e. Bus11-2 and Bus11-6, and three demand-dominated busbars, i.e. Bus11-7, Bus11-9 and Bus04-1.

The data of busbars, generators, lines, transformers and loads of the reference network are presented in appendix 1.

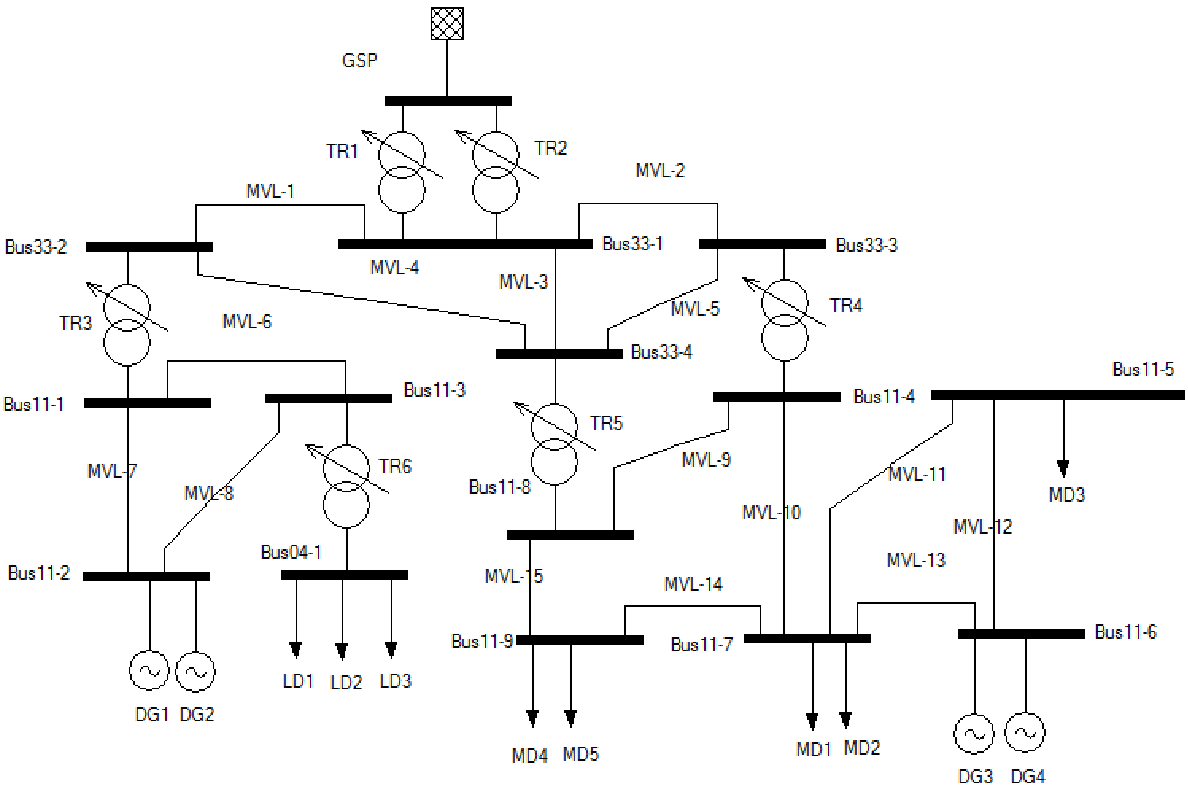

Figure 3.2 The reference network

B. Load Flow Analysis of the Reference Network

The IPSA software version 1.6.9 can be used to analysis the voltage level, power flow and power losses of the reference network through load flow analysis mechanisms. There are two types of load flow analyse in this software, i.e. busbar load flow analysis and line load flow analysis. The busbar load flow analysis will examine the voltage magnitude and the voltage angle of each busbar on the network. While the lines load flow analysis will examine the power flow and power losses on each line on the network.

1). Busbar Load Flow Analysis

Table 3.1 shows the results of busbar load flow analysis of the reference network in figure 3.2. Besides the voltage magnitude and angle for each busbar, the table also shows the generation and load which are connected to each busbar, as well as the total connected generation and load on the network.

Name	Voltage Magnitude (pu)	Voltage Angle (deg)	Total Real Generation (MW)	Total Reactive Generation (MVAr)	Total Real Load (MW)	Total Reactive Load (MVAr)	Mismatch (MW)	Mismatch (MVAr)
GSP	1.000		2.262	0.419			-0.000	0.000
Bus33-1	0.999	-0.20					0.000	-0.000
Bus33-2	1.000	-0.18					-0.000	0.000
Bus11-1	1.020	4.25					-0.000	0.000
Bus11-2	1.031	4.51	9.900	4.790			0.000	0.000
Bus11-3	1.021	4.37					0.000	0.000
Bus04-1	0.933	-0.10			3.600	2.700	0.000	-0.000
Bus33-4	0.999	-0.21					0.000	-0.000
Bus11-8	0.985	-3.37					0.000	0.000
Bus11-9	0.977	-3.69			6.660	2.180	-0.000	0.000
Bus33-3	0.998	-0.22					-0.000	-0.000
Bus11-4	0.987	-3.35					0.000	0.000
Bus11-7	0.981	-3.63			7.600	2.500	-0.000	0.000
Bus11-5	0.983	-3.63			3.800	1.250	0.000	-0.000
Bus11-6	0.993	-3.42	9.900	4.790			-0.000	-0.000

Table 3.1 Busbar Load Flow Results for the Reference Network

2). Line Load Flow Analysis

The line load flow analysis can be used to examine the power flow and power losses on each line of the network, in the forms of real power (MW), reactive power (MVAr) and apparent power (MVA). The results of the line load flow analysis are presented in table 3.2

From Busbar	To Busbar	Standard Rating (MVA)	Send Apparent Power (MVA)	Receive Apparent Power (MVA)	Real Power Losses (MW)	Reactive Power Losses (MVAr)
GSP	Bus33-1	40.000	1.150	1.149	0.000	0.004
GSP	Bus33-1	40.000	1.150	1.149	0.000	0.004
Bus33-2	Bus33-1	15.433	2.262	2.269	0.002	-0.054
Bus33-2	Bus11-1	10.000	6.172	6.299	0.028	0.498
Bus11-1	Bus11-2	7.049	5.702	5.756	0.046	0.031
Bus11-1	Bus11-3	7.049	0.990	0.998	0.001	-0.013
Bus11-3	Bus04-1	7.500	4.923	4.500	0.096	0.552
Bus33-4	Bus11-8	10.000	4.292	4.234	0.013	0.242
Bus11-8	Bus11-9	7.049	4.908	4.867	0.036	0.023
Bus33-1	Bus33-4	15.433	1.643	1.653	0.001	-0.054
Bus33-1	Bus33-3	15.433	2.925	2.932	0.003	-0.053
Bus33-3	Bus11-4	10.000	4.218	4.169	0.013	0.234
Bus11-3	Bus11-2	7.049	5.232	5.277	0.038	0.024
Bus11-4	Bus11-8	7.049	0.709	0.714	0.001	-0.013
Bus33-3	Bus33-4	15.433	1.286	1.278	0.001	-0.054
Bus33-2	Bus33-4	15.433	3.910	3.915	0.005	-0.052
Bus11-5	Bus11-7	7.049	1.048	1.055	0.002	-0.012
Bus11-9	Bus11-7	7.049	2.232	2.236	0.008	-0.006
Bus11-4	Bus11-7	7.049	3.520	3.502	0.019	0.005
Bus11-7	Bus11-6	7.049	5.936	6.002	0.053	0.040
Bus11-5	Bus11-6	7.049	4.958	5.002	0.037	0.023

Table 3.2 Line Load Flow Results for Reference Network

The IPSA software version 1.6.9 can also be used to depict the results given in table 3.1 and 3.2 on a model network. As seen in figure 3.3, the voltage magnitudes (pu) and voltage angle for each busbar are presented. Per unit (pu) of voltage magnitudes is the ratio of actual voltage level and rated voltage level of each busbar. The figure also shows the power generated from each generators and the power absorbed by each connected load.

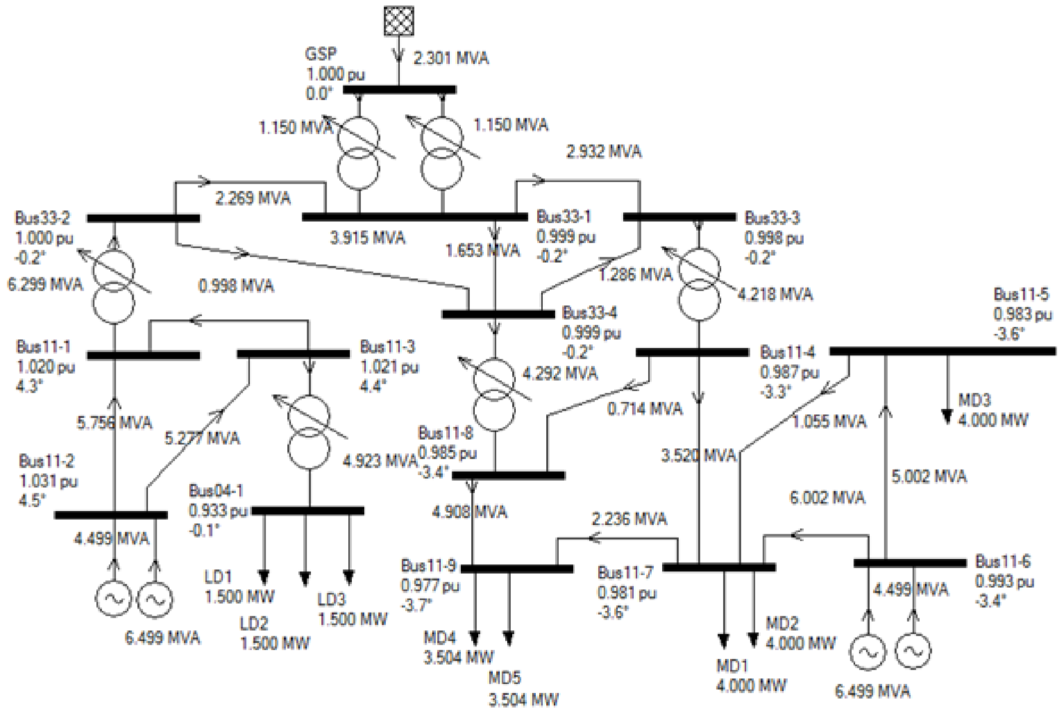

Figure 3.3 Voltage Level and Power Flow of the Reference Network

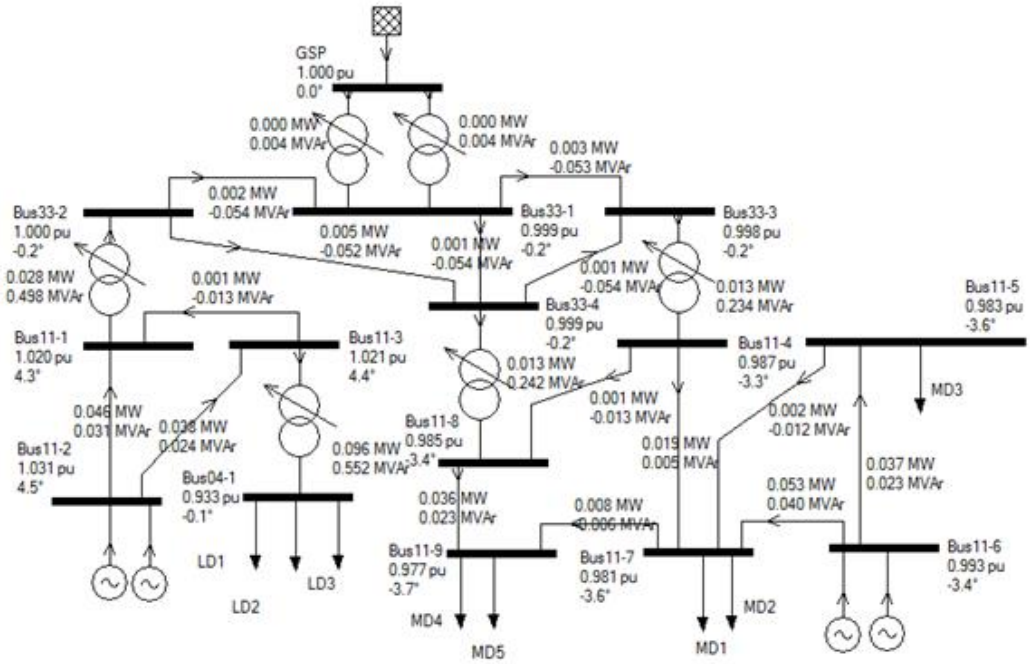

Figure 3.4 Voltage Level and Power Losses of the Reference Network

Besides the voltage level and power flow of the network, the IPSA software version 1.6.9 can also be used to show the power losses of the modelled network, as depicted in figure 3.4

3.1.2 DG Connection at a Generation-dominated Busbar

There are two generation-dominated busbars on the reference network, i.e. Bus11-2, and Bus11-6. In order to analyse the impact of DG connection, a new DG will be connected to one of these busbars. The DG is assumed to be an onshore wind generation with the capacity of 4.5MVA, the power factor of 0.9 and the capacity factor of 0.35. The impact of connecting a new DG to those busbars, in terms of voltage level, network capacity utilization and power losses are explained as follows.

1) Impact of DG Connection on the Voltage Level

In terms of voltage level, the impact of a new DG connection at a generation-dominated busbar is presented in table 3.3. The terms of dV in table 3.8 represents the changes of voltage level. The unit of dV is expressed in percent (%), which can be obtained from the following equation [74]:

$$\mathrm{dV}\ (\%) = \frac{\mathrm{kV_n} - \mathrm{kV_0}}{\mathrm{kV_0}} \mathrm{x}100\% \qquad \text{... (3.6)}$$

Where $\mathrm{kV_0}$ is the initial voltage magnitude and $\mathrm{kV_n}$ is the voltage magnitude after a new DG connected to a designated bus bar.

Bus Name	Initial Network		DG Connection at Bus11-2			DG Connection at Bus11-6		
	Voltage Mag (pu)	**Voltage Angle (deg)**	**Voltage Mag (pu)**	**Voltage Angle (deg)**	**dV**	**Voltage Mag (pu)**	**Voltage Angle (deg)**	**dV**
GSP	1		1			1		
Bus33-1	0.999	-0.2	1.001	0.15	0.2%	1.003	0.15	0.4%
Bus33-2	1	-0.18	1.003	0.18	0.3%	1.004	0.17	0.4%
Bus11-1	1.02	4.25	1.045	7.28	2.5%	1.025	4.57	0.5%
Bus11-2	1.031	4.51	1.061	7.63	2.9%	1.035	4.82	0.4%
Bus11-3	1.021	4.37	1.048	7.44	2.6%	1.025	4.68	0.4%
Bus04-1	0.933	-0.1	0.963	3.22	3.2%	0.938	0.25	0.5%
Bus33-4	0.999	-0.21	1.001	0.14	0.2%	1.003	0.14	0.4%
Bus11-8	0.985	-3.37	0.987	-3.01	0.2%	1.004	-1.51	1.9%
Bus11-9	0.977	-3.69	0.979	-3.33	0.2%	0.999	-1.76	2.3%
Bus33-3	0.998	-0.22	1	0.13	0.2%	1.003	0.13	0.5%
Bus11-4	0.987	-3.35	0.989	-2.98	0.2%	1.007	-1.47	2.0%
Bus11-7	0.981	-3.63	0.983	-3.27	0.2%	1.007	-1.64	2.7%
Bus11-5	0.983	-3.63	0.986	-3.27	0.3%	1.012	-1.58	3.0%
Bus11-6	0.993	-3.42	0.995	-3.05	0.2%	1.024	-1.32	3.1%

Table 3.3 Impact of DG Connection on Voltage Level at Generation-dominated Busbars

As presented in table 3.3, the connection of a new DG to a generation-dominated busbar will increase the network's voltage level, especially for the busbars which are close and interconnected with the targeted busbar.

DG connection at Bus11-2 will increase the initial voltage level of the related busbars to increase by 2.5% until 2.9%. The same impact also occurs in the connection of a new DG at Bus11-6, which causes the initial voltage level of the related busbars to increase by 2.7% until 3.1%. The highest increase of the voltage level occurs on the targeted busbar, where the DG is connected.

2) Impact of DG Connection on the Network Capacity Utilization

Table 3.4 shows the impact of connecting a new DG to a generation-dominated busbar on the network capacity utilization of related busbars on the network. The terms of $dS_{powerflow}$ in table 3.9 represents the changes of the network utilization of a particular busbar. The unit of dSpowerflow is expressed in percent (%), which can be derived from [74]:

$$dS_{Power\ Flow}\ (\%) = \frac{S_{powerflow-n} - S_{powerflow-o}}{S_{powerflow-o}} x100\% \qquad \text{... (3.7)}$$

Where $S_{powerflow-o}$ is the initial power flow of the line and $S_{powerflow-n}$ is the power flow of the line after DG to the network took place.

From Busbar	**To Busbar**	**Power Rating (MVA)**	**Network Capacity Utilization**					
			Initial		**DG Connection at Bus11-2**		**DG Connection at Bus11-6**	
GSP	Bus33-1	40.000	1.150	2.9%	0.889	2.2%	1.272	3.2%
GSP	Bus33-1	40.000	1.150	2.9%	0.889	2.2%	1.272	3.2%
Bus33-2	Bus33-1	15.433	2.269	14.7%	4.799	31.1%	3.094	20.0%
Bus33-2	Bus11-1	10.000	6.299	63.0%	10.656	106.6%	6.302	63.0%
Bus11-1	Bus11-2	7.049	5.756	81.7%	8.753	124.2%	5.757	81.7%
Bus11-1	Bus11-3	7.049	0.998	14.2%	2.143	30.4%	0.997	14.1%
Bus11-3	Bus04-1	7.500	4.923	65.6%	4.896	65.3%	4.919	65.6%
Bus33-4	Bus11-8	10.000	4.292	42.9%	4.295	43.0%	2.220	22.2%
Bus11-8	Bus11-9	7.049	4.908	69.6%	4.908	69.6%	3.321	47.1%
Bus33-1	Bus33-4	15.433	1.653	10.7%	0.636	4.1%	0.548	3.6%
Bus33-1	Bus33-3	15.433	2.932	19.0%	2.425	15.7%	1.231	8.0%
Bus33-3	Bus11-4	10.000	4.218	42.2%	4.213	42.1%	2.174	21.7%
Bus11-3	Bus11-2	7.049	5.277	74.9%	6.695	95.0%	5.276	74.8%
Bus11-4	Bus11-8	7.049	0.714	10.1%	0.710	10.1%	1.236	17.5%
Bus33-3	Bus33-4	15.433	1.286	8.3%	1.788	11.6%	1.009	6.5%
Bus33-2	Bus33-4	15.433	3.915	25.4%	5.433	35.2%	3.116	20.2%
Bus11-5	Bus11-7	7.049	1.055	15.0%	1.056	15.0%	2.487	35.3%
Bus11-9	Bus11-7	7.049	2.236	31.7%	2.235	31.7%	3.874	55.0%
Bus11-4	Bus11-7	7.049	3.520	49.9%	3.520	49.9%	1.435	20.4%
Bus11-7	Bus11-6	7.049	6.002	85.1%	6.002	85.1%	8.998	127.6%
Bus11-5	Bus11-6	7.049	5.002	71.0%	5.002	71.0%	6.504	92.3%

Table 3.4 Impact of DG Connection on Network Capacity Utilization

As presented in table 3.4, the connection of a new DG connection to one of generation-dominated busbars, either Bus11-2 or Bus11-6 will increase the network capacity utilization of the lines which are connected to the targeted busbar.

Due to DG connection at Bus11-2 the network capacity utilization of the line between Bus11-2 and Bus11-1 increases from 81.7% to 124.2%. This connection also increases the network capacity utilization of the line between Bus11-2 and Bus11-3, from 74.9% to 95.0%. The similar impact also occurs when a new DG connected to Bus11-6. This connection causes network utilization to increase from 85.1% to 127.6% on the line between Bus11-6 and Bus11-7, and on the line between Bus11-6 and Bus11-5, the network capacity utilization increases from 71.0% to 92.3%.

The increase of the network capacity utilization is caused by the increase of the power which is flowing through the lines. This due to the energy generated from the new DG connection is distributed in the same direction with the initial power flow of those lines, so that, those two powers will add each other.

3) Impact of DG Connection on the Power Losses

The impact of connecting a new DG to a generation-dominated busbar on the power losses of the lines is presented in table 3.5 and 3.6. Table 3.5 shows the impact of DG connection at Bus11-2, while table 3.6 shows the impact of DG connection at Bus11-6. The terms of $\mathrm{dS_{Losses}}$ represents the changes of power losses on a particular line. The unit of $\mathrm{dS_{Losses}}$ is expressed in percent (%), which can be obtained by using the following equation [74]:

$$\mathrm{dS_{Losses}}\ (\%) = \frac{\mathrm{S_{Losses-n}} - \mathrm{S_{Losses-o}}}{\mathrm{S_{Losses-o}}} \mathrm{x}100\% \qquad \text{... (3.8)}$$

Where $\mathrm{S_{Losses\text{-}o}}$ is the power losses of the initial network and $\mathrm{S_{Losses\text{-}n}}$ is the power losses after a new DG connected to the network.

From Busbar	To Busbar	Power Losses						
		Initial Network			DG Connection at Bus11-2			
		(MW)	(MVAr)	(MVA)	(MW)	(MVAr)	(MVA)	dSlosses
GSP	Bus33-1	0	0.004	0.004	0	0.002	0.002	-50.0%
GSP	Bus33-1	0	0.004	0.004	0	0.002	0.002	-50.0%
Bus33-2	Bus33-1	0.002	-0.054	0.054	0.007	-0.051	0.051	-4.7%
Bus33-2	Bus11-1	0.028	0.498	0.499	0.075	1.361	1.363	173.3%
Bus11-1	Bus11-2	0.046	0.031	0.055	0.1	0.083	0.130	134.3%
Bus11-1	Bus11-3	0.001	-0.013	0.013	0.006	-0.009	0.011	-17.0%
Bus11-3	Bus04-1	0.096	0.552	0.560	0.091	0.518	0.526	-6.1%
Bus33-4	Bus11-8	0.013	0.242	0.242	0.013	0.241	0.241	-0.4%
Bus11-8	Bus11-9	0.036	0.023	0.043	0.036	0.023	0.043	0.0%
Bus33-1	Bus33-4	0.001	-0.054	0.054	0	-0.055	0.055	1.8%
Bus33-1	Bus33-3	0.003	-0.053	0.053	0.002	-0.054	0.054	1.8%
Bus33-3	Bus11-4	0.013	0.234	0.234	0.013	0.232	0.232	-0.9%
Bus11-3	Bus11-2	0.038	0.024	0.045	0.06	0.044	0.074	65.5%
Bus11-4	Bus11-8	0.001	-0.013	0.013	0.001	-0.013	0.013	0.0%
Bus33-3	Bus33-4	0.001	-0.054	0.054	0.001	-0.054	0.054	0.0%
Bus33-2	Bus33-4	0.005	-0.052	0.052	0.009	-0.049	0.050	-4.6%
Bus11-5	Bus11-7	0.002	-0.012	0.012	0.002	-0.012	0.012	0.0%
Bus11-9	Bus11-7	0.008	-0.006	0.010	0.008	-0.006	0.010	0.0%
Bus11-4	Bus11-7	0.019	0.005	0.020	0.019	0.005	0.020	0.0%
Bus11-7	Bus11-6	0.053	0.04	0.066	0.053	0.039	0.066	-0.9%
Bus11-5	Bus11-6	0.037	0.023	0.044	0.037	0.023	0.044	0.0%
Total Power Losses		0.403	1.369	1.427	0.533	2.27	2.332	63.4%

Table 3.5 Impact of DG Connection on Power Losses at Bus11-2

As seen in table 3.5, DG connection at Bus11-2 will increase the power losses on the lines which are directly connected to Bus11-2. This connection increases the power losses of the line between Bus11-2 and Bus11-1 by 134.3%, compared with the initial level. This connection also increases the initial power losses of the line between Bus11-2 and Bus11-3 by and 65.5%.

From Busbar	To Busbar	Power Losses						
		Initial Network			DG Connection at Bus11-6			
		(MW)	(MVAr)	(MVA)	(MW)	(MVAr)	(MVA)	dSlosses
GSP	Bus33-1	0	0.004	0.004	0	0.005	0.005	25.0%
GSP	Bus33-1	0	0.004	0.004	0	0.005	0.005	25.0%
Bus33-2	Bus33-1	0.002	-0.054	0.054	0.003	-0.053	0.053	-1.8%
Bus33-2	Bus11-1	0.028	0.498	0.499	0.027	0.495	0.496	-0.6%
Bus11-1	Bus11-2	0.046	0.031	0.055	0.045	0.03	0.054	-2.5%
Bus11-1	Bus11-3	0.001	-0.013	0.013	0.001	-0.013	0.013	0.0%
Bus11-3	Bus04-1	0.096	0.552	0.560	0.096	0.546	0.554	-1.1%
Bus33-4	Bus11-8	0.013	0.242	0.242	0.004	0.064	0.064	-73.5%
Bus11-8	Bus11-9	0.036	0.023	0.043	0.016	0.002	0.016	-62.3%
Bus33-1	Bus33-4	0.001	-0.054	0.054	0	-0.055	0.055	1.8%
Bus33-1	Bus33-3	0.003	-0.053	0.053	0	-0.055	0.055	3.6%
Bus33-3	Bus11-4	0.013	0.234	0.234	0.003	0.061	0.061	-73.9%
Bus11-3	Bus11-2	0.038	0.024	0.045	0.038	0.023	0.044	-1.2%
Bus11-4	Bus11-8	0.001	-0.013	0.013	0.002	-0.012	0.012	-6.7%
Bus33-3	Bus33-4	0.001	-0.054	0.054	0	-0.055	0.055	1.8%
Bus33-2	Bus33-4	0.005	-0.052	0.052	0.003	-0.053	0.053	1.6%
Bus11-5	Bus11-7	0.002	-0.012	0.012	0.009	-0.005	0.010	-15.4%
Bus11-9	Bus11-7	0.008	-0.006	0.010	0.022	0.008	0.023	134.1%
Bus11-4	Bus11-7	0.019	0.005	0.020	0.003	-0.011	0.011	-42.0%
Bus11-7	Bus11-6	0.053	0.04	0.066	0.113	0.098	0.150	125.3%
Bus11-5	Bus11-6	0.037	0.023	0.044	0.059	0.044	0.074	68.9%
Total Losses		0.403	1.369	1.427	0.445	1.069	1.158	-18.8%

Table 3.6 Impact of DG Connection on Power Losses at Bus11-6

Table 3.6 shows that the connection of a new DG at Bus11-6 causes the increase of power losses on the lines which are connected to Bus11-6. This connection increases the power losses of the line between Bus11-6 and Bus11-5 by 68%, compared with the initial level. This connection also increases the initial power losses of the line between Bus11-6 and Bus11-7 by 125.3%.

The increase of power losses in both cases is caused by increase of power which is flowing through those lines. The energy generated from the new DG connection at Bus11-2 or Bus11-6 will be distributed through those lines in the same direction with the initial power flow. This will increase the amount of power which is flowing through those lines. As the power flow increased, the power losses will increase as well.

To be clear, the results of the above analysis can be depicted on a network model, as depicted in figure 3.5 and 3.6.

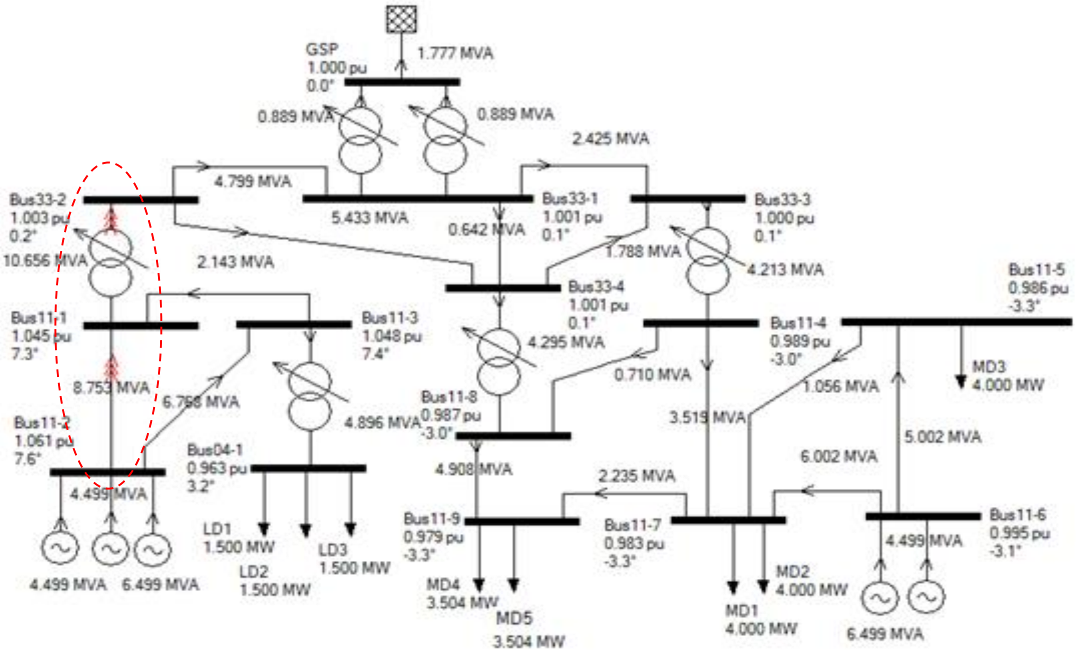

Figure 3.5 Load Flow Analysis for DG Connection at Bus11-2

As shown in figure 3.5, the connection of a new DG at Bus11-2 causes the power flow on some branches/lines are exceeding the capacity standard of those lines. The amount of power flow on the line between Bus11-2 and Bus11-1 is 8.753MVA, exceeding its capacity rating of 7.049MVA. While on the line between Bus11-1 and Bus33-2, the amount of power is 10.656MVA, exceeding the line's capacity standard of 10.000MVA.

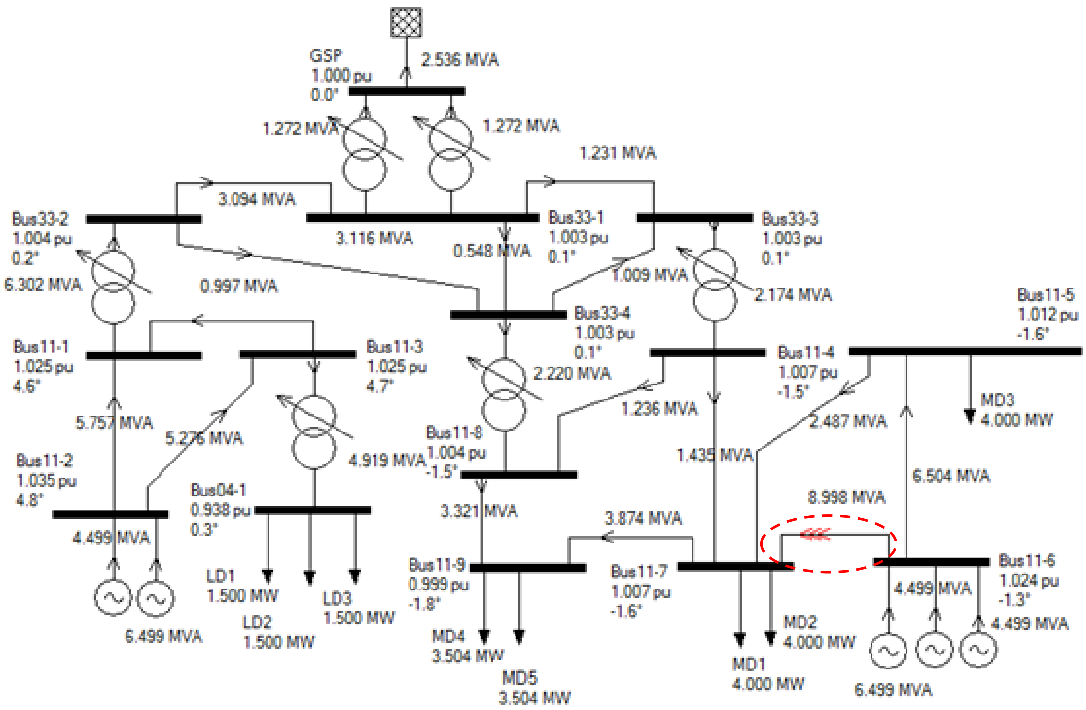

Figure 3.6 Load Flow Analysis for DG Connection at Bus11-6

Figure 3.6 shows the impact of a new DG connection to Bus11-6. This connection causes the power flow on the line between Bus11-6 and Bus11-7 to increase up to 8.998MVA, exceeding its capacity standard of 7.049MVA.

3.1.3 DG Connection at a Demand-dominated Busbar

The impact of DG connection on a demand-dominated busbar is investigated using the same reference network depicted in figure 3.1. There are three demand-dominated busbars on the network, i.e. Bus11-7, Bus11-9, and Bus04-1. Since the DG will operate at 11kV, the analysis includes the 11kV busbars only. The DG that will be connected to the network is assumed to be an onshore wind generation with the capacity of 4.5MVA, the power factor of 0.9 and the capacity factor of 0.35. The following sections describe the impact of connecting a new DG to those busbars, in terms of voltage level, network capacity utilization and power losses.

1) Impact of DG Connection on the Voltage Level

Busbar Name	Initial Network		DG Connection at Bus11-7			DG Connection at Bus11-9		
	Voltage Mag (pu)	Voltage Angle (deg)	Voltage Mag (pu)	Voltage Angle (deg)	dV	Voltage Mag (pu)	Voltage Angle (deg)	dV
GSP	1		1		0.0%	1		0.0%
Bus33-1	0.999	-0.2	1.003	0.16	0.4%	1.003	0.16	0.4%
Bus33-2	1	-0.18	1.004	0.17	0.4%	1.004	0.18	0.4%
Bus11-1	1.02	4.25	1.025	4.57	0.5%	1.025	4.58	0.5%
Bus11-2	1.031	4.51	1.035	4.83	0.4%	1.035	4.83	0.4%
Bus11-3	1.021	4.37	1.025	4.68	0.4%	1.025	4.69	0.4%
Bus04-1	0.933	-0.1	0.938	0.26	0.5%	0.938	0.26	0.5%
Bus33-4	0.999	-0.21	1.003	0.14	0.4%	1.003	0.15	0.4%
Bus11-8	0.985	-3.37	1.005	-1.47	2.0%	1.006	-1.44	2.1%
Bus11-9	0.977	-3.69	1	-1.72	2.4%	1.003	-1.64	2.7%
Bus33-3	0.998	-0.22	1.003	0.13	0.5%	1.003	0.14	0.5%
Bus11-4	0.987	-3.35	1.008	-1.43	2.1%	1.007	-1.44	2.0%
Bus11-7	0.981	-3.63	1.008	-1.59	2.8%	1.005	-1.65	2.4%
Bus11-5	0.983	-3.63	1.01	-1.6	2.7%	1.007	-1.65	2.4%
Bus11-6	0.993	-3.42	1.019	-1.39	2.6%	1.016	-1.44	2.3%

Table 3.7 Impact of DG Connection on Voltage Level at Demand-dominated Busbars

Table 3.7 shows the impact of connecting a new DG to a demand-dominated area on the voltage level of related busbars. This connection increases of the network's voltage level, especially for the busbars which are close and interconnected with the targeted busbar. DG connection at Bus11-7 will increase the initial voltage level of related busbars by 2.1% until 2.8%. While the connection of a new DG at Bus11-9 causes the initial voltage level of related busbars to increase by 2.1% until 2.7%. The highest increase of the voltage level occurs on the targeted busbar, where the DG is connected.

2) Impact of DG Connection on the Network Capacity Utilization

Table 3.8 shows the impact of connecting a new DG to a demand-dominated area on the network capacity utilization of the busbars which are connected to the targeted busbar.

From Busbar	To Busbar	Power Rating (MVA)	Network Capacity Utilization					
			Initial		DG Connection at Bus11-7		DG Connection at Bus11-9	
GSP	Bus33-1	40.000	1.150	2.9%	1.339	3.3%	1.360	3.4%
GSP	Bus33-1	40.000	1.150	2.9%	1.339	3.3%	1.360	3.4%
Bus33-2	Bus33-1	15.433	2.269	14.7%	3.115	20.2%	3.128	20.3%
Bus33-2	Bus11-1	10.000	6.299	63.0%	6.302	63.0%	6.302	63.0%
Bus11-1	Bus11-2	7.049	5.756	81.7%	5.757	81.7%	5.757	81.7%
Bus11-1	Bus11-3	7.049	0.998	14.2%	0.997	14.1%	0.997	14.1%
Bus11-3	Bus04-1	7.500	4.923	65.6%	4.919	65.6%	4.919	65.6%
Bus33-4	Bus11-8	10.000	4.292	42.9%	2.180	21.8%	2.148	21.5%
Bus11-8	Bus11-9	7.049	4.908	69.6%	3.283	46.6%	2.248	31.9%
Bus33-1	Bus33-4	15.433	1.653	10.7%	0.578	3.7%	0.606	3.9%
Bus33-1	Bus33-3	15.433	2.932	19.0%	1.213	7.9%	1.205	7.8%
Bus33-3	Bus11-4	10.000	4.218	42.2%	2.139	21.4%	2.143	21.4%
Bus11-3	Bus11-2	7.049	5.277	74.9%	5.276	74.8%	5.276	74.8%
Bus11-4	Bus11-8	7.049	0.714	10.1%	1.251	17.7%	0.185	2.6%
Bus33-3	Bus33-4	15.433	1.286	8.3%	1.003	6.5%	1.025	6.6%
Bus33-2	Bus33-4	15.433	3.915	25.4%	3.097	20.1%	3.087	20.0%
Bus11-5	Bus11-7	7.049	1.055	15.0%	1.058	15.0%	1.058	15.0%
Bus11-9	Bus11-7	7.049	2.236	31.7%	3.921	55.6%	0.594	8.4%
Bus11-4	Bus11-7	7.049	3.520	49.9%	1.437	20.4%	2.055	29.2%
Bus11-7	Bus11-6	7.049	6.002	85.1%	6.003	85.1%	6.003	85.2%
Bus11-5	Bus11-6	7.049	5.002	71.0%	5.001	70.9%	5.001	70.9%

Table 3.8 Impact of DG Connection on Network Utilization at Demand-dominated Busbars

As presented in table 3.8, the connection of a new DG to Bus11-7 causes the network capacity utilization of the line between Bus11-7 and Bus11-4 to decrease from 49.9% down to 20.4%. The reduction of network capacity utilization due to the power generated from the connected DG at Bus11-7 can be used to supply the demand connected to Bus11-7 itself. Since the demand connected to Bus11-7 has been partly supplied by the energy from the new DG, the amount of power which previously flows from Bus11-4 to Bus11-7 will decrease. As the power flow on this line decreases, so does the network capacity utilization. However, this connection will increase the network capacity utilization of another line, such as the line between Bus11-7 and Bus11-9, from 31.7% to 55.6%. This is because the power generated from the connected DG at Bus11-7 can also be used to supply the demand connected at Bus11-9. Since, initially, the power needed to supply demand at Bus11-9 also came from Bus11-7 to Bus119, the additional power from the DG connected at Bus11-7 will increase the total power flow on the line between Bus11-7 and Bus11-9.

To complement the analysis above, the impact of DG connection at Bus11-7 can be seen in figure 3.7. The connection of a new DG to a demand-dominated at Bus11-7, i.e. a demand-dominated busbar, does not cause the standard capacity of related lines which are connected to this busbar to be exceeded.

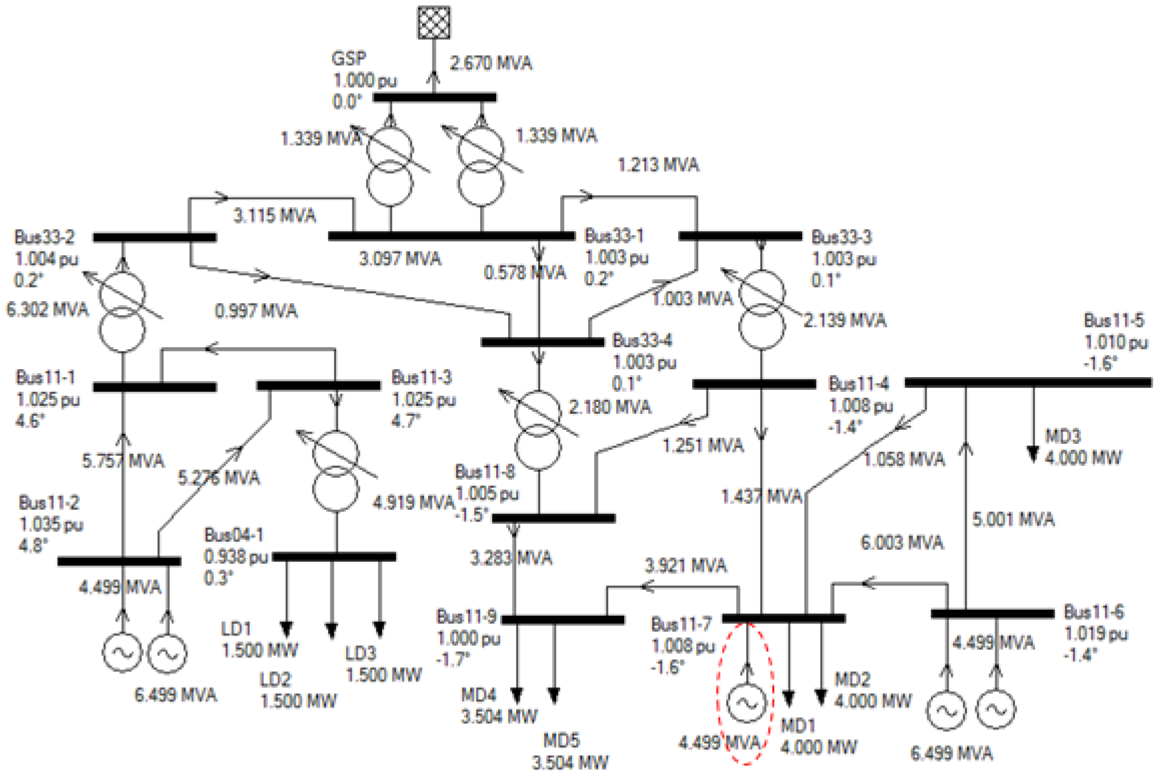

Figure 3.7 A New DG Connection at Demand-dominated Busbar (Bus11-7)

Meanwhile, the connection of a new DG to Bus11-9 will cause the network capacity utilization of the lines connected to Bus11-9 to decrease. This connection reduces the network capacity of the line between Bus11-9 and 11-8, from 69.6% down to 31.9%. In this case, the reduction of the network capacity utilization due to the energy generated from the connected DG at Bus11-9 is used to supply the demand connected at Bus11-9 itself. Since the demand connected to Bus11-9 has been partly supplied by the energy from the new DG, the amount of power which previously flows from Bus11-7 to Bus11-9 will decrease. As the power flow on this line decreases, so does the network capacity utilization. Furthermore, the energy from DG connected at Bus11-9 can also be used to supply demand connected at Bus11-7. This means that the power is flowing from Bus11-9 to Bus-11-7. This power flow is in the opposite direction with the initial one which is flowing from Bus11-7 to Bus11-9. As the result, the total amount of power flow on this line is reduced, which in turn, it will reduce the network capacity utilization of the line. As presented in table 3.13, the network capacity utilization of the line between Bus11-9 and Bus11-7 decreases from 31.7% down to 8.4%.

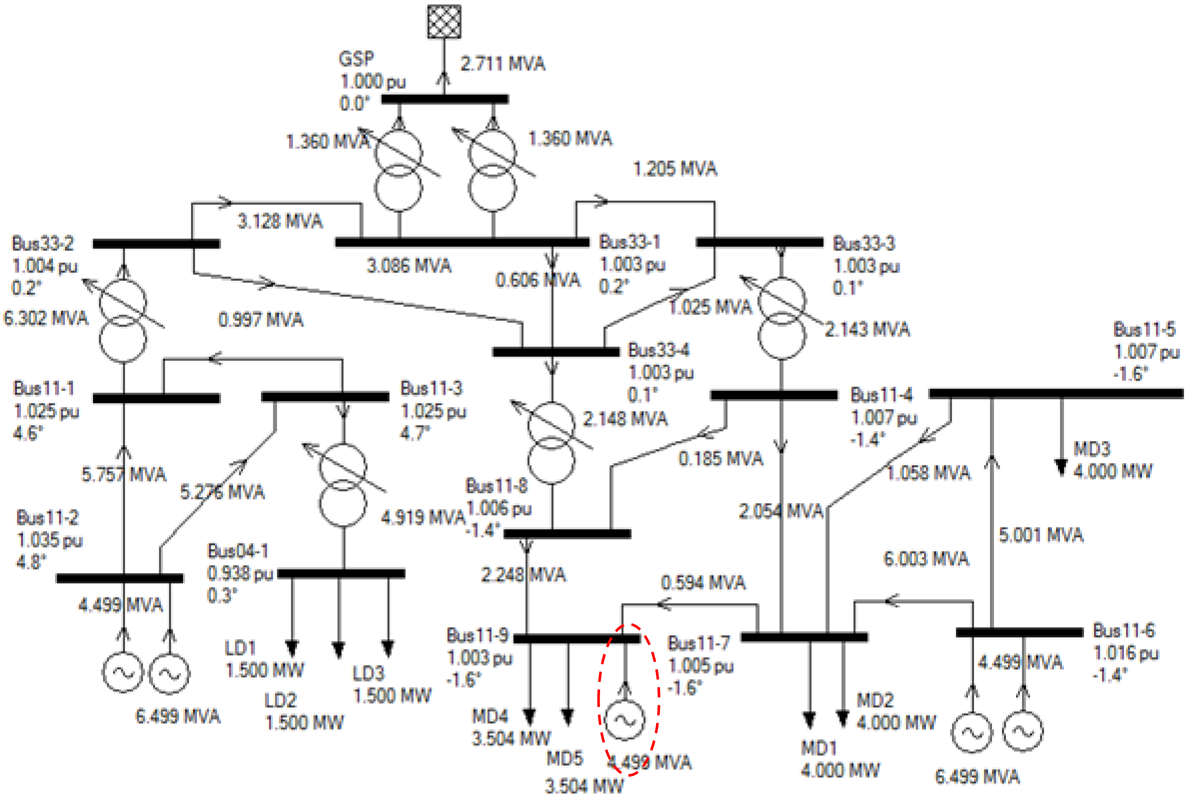

Figure 3.8 A New DG Connection at Demand-dominated Busbar Bus11-9

To complement the analysis above, the impact of DG connection at Bus11-9 can be seen in figure 3.8. The connection of a new DG to a demand-dominated at Bus11-9 does not cause the standard capacity of related lines which are connected to this busbar to be exceeded.

3) Impact of DG Connection on the Power Losses

The impact of connecting a new DG to a demand-dominated on the power losses of the lines which is connected to the targeted busbar are presented in table 3.9 and 3.10. Table 3.9 shows the impact of DG connection at Bus11-7, while table 3.10 shows the impact of DG connection at Bus11-9.

From Busbar	To Busbar	Power Losses						
		Initial Network			DG Connection at Bus11-7			
		(MW)	(MVAr)	(MVA)	(MW)	(MVAr)	(MVA)	dSlosses
GSP	Bus33-1	0	0.004	0.004	0	0.006	0.006	50.0%
GSP	Bus33-1	0	0.004	0.004	0	0.006	0.006	50.0%
Bus33-2	Bus33-1	0.002	-0.054	0.054	0.003	-0.053	0.053	-1.8%
Bus33-2	Bus11-1	0.028	0.498	0.499	0.027	0.495	0.496	-0.6%
Bus11-1	Bus11-2	0.046	0.031	0.055	0.045	0.03	0.054	-2.5%
Bus11-1	Bus11-3	0.001	-0.013	0.013	0.001	-0.013	0.013	0.0%
Bus11-3	Bus04-1	0.096	0.552	0.560	0.095	0.546	0.554	-1.1%
Bus33-4	Bus11-8	0.013	0.242	0.242	0.003	0.062	0.062	-74.4%
Bus11-8	Bus11-9	0.036	0.023	0.043	0.016	0.002	0.016	-62.3%
Bus33-1	Bus33-4	0.001	-0.054	0.054	0	-0.055	0.055	1.8%
Bus33-1	Bus33-3	0.003	-0.053	0.053	0	-0.055	0.055	3.6%
Bus33-3	Bus11-4	0.013	0.234	0.234	0.003	0.059	0.059	-74.8%
Bus11-3	Bus11-2	0.038	0.024	0.045	0.038	0.023	0.044	-1.2%
Bus11-4	Bus11-8	0.001	-0.013	0.013	0.002	-0.012	0.012	-6.7%
Bus33-3	Bus33-4	0.001	-0.054	0.054	0	-0.055	0.055	1.8%
Bus33-2	Bus33-4	0.005	-0.052	0.052	0.003	-0.053	0.053	1.6%
Bus11-5	Bus11-7	0.002	-0.012	0.012	0.002	-0.012	0.012	0.0%
Bus11-9	Bus11-7	0.008	-0.006	0.010	0.022	0.008	0.023	134.1%
Bus11-4	Bus11-7	0.019	0.005	0.020	0.003	-0.011	0.011	-42.0%
Bus11-7	Bus11-6	0.053	0.04	0.066	0.051	0.036	0.062	-6.0%
Bus11-5	Bus11-6	0.037	0.023	0.044	0.035	0.021	0.041	-6.3%
Total Losses		0.403	1.369	1.427	0.349	0.975	1.036	-27.4%

Table 3.9 Impact of DG Connection on Power Losses at Bus11-7

As presented in table 3.9, the connection of a new DG at Bus11-7 causes the power losses of the line between Bus11-7 and Bus11-9 to increase by 134% from the initial level. This due to the energy generated from the new DG is distributed at the same direction with the existing power flow to supply the demand at Bus11-9. This will increase the amount of power flow on the line. As the power flow increases, so does the power losses. However, this connection causes the decrease of power losses of other lines. The power losses of the line between Bus11-7 and Bus11-6 decreases by 42% from the initial level, while the initial power losses of the line between Bus11-7 and Bus11-4 decreases by 6%. The decrease of power losses due to the energy from DG at Bus11-7 is used to supply demand at Bus11-7 itself. Because the demand connected at Bus11-7 has partly supplied, the power which previously flows from Bus11-4 to Bus11-7 to supply the demand will be reduced. As a result, this will reduce the power flow of the line. As the power flow decreases, so does the power losses.

From Busbar	To Busbar	Power Losses						
		Initial Network			DG Connection at Bus11-9			
		(MW)	(MVAr)	(MVA)	(MW)	(MVAr)	(MVA)	dSlosses
GSP	Bus33-1	0	0.004	0.004	0	0.006	0.006	50.0%
GSP	Bus33-1	0	0.004	0.004	0	0.006	0.006	50.0%
Bus33-2	Bus33-1	0.002	-0.054	0.054	0.003	-0.053	0.053	-1.8%
Bus33-2	Bus11-1	0.028	0.498	0.499	0.027	0.495	0.496	-0.6%
Bus11-1	Bus11-2	0.046	0.031	0.055	0.045	0.03	0.054	-2.5%
Bus11-1	Bus11-3	0.001	-0.013	0.013	0.001	-0.013	0.013	0.0%
Bus11-3	Bus04-1	0.096	0.552	0.560	0.095	0.546	0.554	-1.1%
Bus33-4	Bus11-8	0.013	0.242	0.242	0.003	0.06	0.060	-75.2%
Bus11-8	Bus11-9	0.036	0.023	0.043	0.007	-0.007	0.010	-76.8%
Bus33-1	Bus33-4	0.001	-0.054	0.054	0	-0.055	0.055	1.8%
Bus33-1	Bus33-3	0.003	-0.053	0.053	0	-0.055	0.055	3.6%
Bus33-3	Bus11-4	0.013	0.234	0.234	0.003	0.059	0.059	-74.8%
Bus11-3	Bus11-2	0.038	0.024	0.045	0.038	0.023	0.044	-1.2%
Bus11-4	Bus11-8	0.001	-0.013	0.013	0	-0.014	0.014	7.4%
Bus33-3	Bus33-4	0.001	-0.054	0.054	0	-0.055	0.055	1.8%
Bus33-2	Bus33-4	0.005	-0.052	0.052	0.003	-0.053	0.053	1.6%
Bus11-5	Bus11-7	0.002	-0.012	0.012	0.002	-0.012	0.012	0.0%
Bus11-9	Bus11-7	0.008	-0.006	0.010	0.001	-0.013	0.013	30.4%
Bus11-4	Bus11-7	0.019	0.005	0.020	0.006	-0.008	0.010	-49.1%
Bus11-7	Bus11-6	0.053	0.04	0.066	0.051	0.037	0.063	-5.1%
Bus11-5	Bus11-6	0.037	0.023	0.044	0.035	0.021	0.041	-6.3%
Total Losses		0.402	1.369	1.427	0.323	0.944	0.998	-30.1%

Table 3.10 Impact of DG Connection on Power Losses at Bus11-9

Table 3.10 presents the impact of connecting a new DG to Bus11-9, which is a demand-dominated busbar. This connection has the same impact as connecting DG to Bus11-7, i.e. in one hand, it will increase the power flow of some lines, but on the other hand, it will increase the power losses of other lines. As shown in table 3.15, this connection causes the power losses on the line between Bus11-9 and Bus11-7 to increase by 30% from the initial level. The increase occurs due to the energy from DG at Bus11-9 is also distributed in the same direction with the initial power flow, to supply the demand at Bus11-7. So that, the power flow on that line will increase. As the power flow increase, the power losses will increase as well.

Different impact of the connection occurs on the line between Bus11-9 and Bus11-8, of which, the power losses on this lines decreases by 76.8% from the initial level. The decrease occurs due to the energy from DG at Bus11-7 can be used to supply demand at Bus11-9 itself. As the demand has been partly supplied, the required power which is previously flows from Bus11-8 to Bus11-9 will be reduced. So, this will reduce the power flow on the line. For the result of the decrease of power flow, the power losses on the line will decrease.

3.1.4 DG Curtailment and Network Reinforcement

Impact of DG connection on DG curtailment and network reinforcement can be examined in the event of connecting a new DG to a generation-dominated busbar. As explained in the previous section, this connection might cause failure in the network due to the power flowing through one or more lines of the network exceeding the standard capacity of those lines.

In order to deal with this condition, there are two options that can be taken into account, i.e. DG curtailment and network reinforcement. DG curtailment is a mechanism to curtail the output energy of the DG to suit the standard capacity of a line/branch. While network reinforcement, is done by upgrading the capacity of the line/branch to accommodate all available DG capacity.

By referring to figure 3.4 and figure 3.5, the connection of a new DG at a generation-dominated busbar, either to Bus11-2 or Bus11-6 will increase the power flow on the lines connected to the designated busbar. The DG connection at Bus11-2 will cause the power flowing through the lines between Bus11-2 and Bus11-1 and between Bus11-1 and Bus33-2 exceed the standard capacity of those lines. While connecting a new DG at Bus11-6, it will increase the power flowing through the line between Bus11-6 and Bus11-7 exceeding the standard capacity of that line.

Figure 3.9 shows a closer look of the impact of connecting a new DG to one of generation-dominated busbars, i.e. Bus11-2 and Bus11-6.

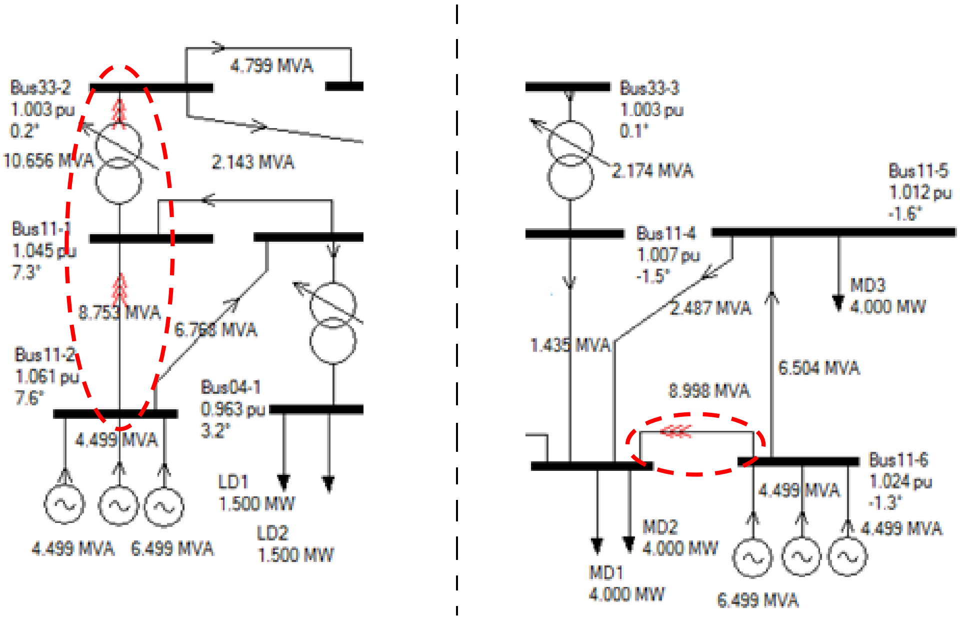

Figure 3.9 Impact of DG connection at Bus11-2 and Bus11-6

A. DG Curtailment Scheme

There are three parameters that must be considered in DG Curtailment scheme, i.e. power flow sensitivity factor, energy curtailment and energy curtailment cost.

1). Power Flow Sensitivity Factor

The active and reactive power flow of a simple network consisting of two nodes, p and q, as depicted in figure 3.10 can be expressed as a function of bus voltage magnitude and phase angle as follows [73]:

$$P_m = G_m|V_i|^2 - G_m|V_i||V_k|\cos(\delta_i - \delta_k) - B_m|V_i||V_k|\sin(\delta_i - \delta_k) \quad ..(3.9)$$

$$Q_m = -B_m|V_i|^2 + B_m|V_i||V_k|\cos(\delta_i - \delta_k) - G_m|V_i||V_k|\sin(\delta_i - \delta_k) \quad ..(3.10)$$

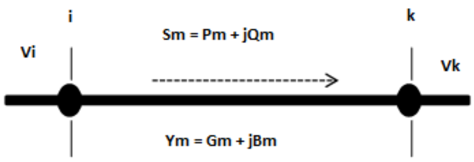

Figure 3.10 A Simple Network Diagram with Two Nodes

The concept of sensitivity factor is derived from the following equation [73]:

$$P_m = P_m^0 + \Delta P_m \quad ..(3.11)$$

Where, (P_m^0) is the base case active power flow and (ΔP_m) is incremental active power flow. By applying partial derivative of (3.8), ΔP_m can be expressed as a function of the bus power injection with variables P_i and Q_i [73]:

$$\Delta P_m = \sum_{i=1}^{NB} \frac{\partial P_m}{\partial P_i} \Delta P_i + \sum_{i=1}^{NB} \frac{\partial P_m}{\partial Q_i} \Delta Q_i \quad ..(3.12)$$

In which, $\frac{\partial P_m}{\partial P_i}$ and $\frac{\partial P_m}{\partial Q_i}$ are the representation of the sensitivity of bus i to line m, i.e. the line between bus p and bus q. ΔP_i and ΔQ_i are the representation of the incremental of active and reactive power in bus i. NB represents the number of busbars in the system.

By replacing the element of $\frac{\partial P_m}{\partial P_i}$ with $F_p(m.i)$ and element of $\frac{\partial P_m}{\partial Q_i}$ with $K_p(m.i)$, equation (3.12) can be written as [73]:

$$\Delta P_m = \sum_{i=1}^{NB} F_p(m.i)\ \Delta P_i + \sum_{i=1}^{NB} K_p(m.i)\,\Delta Q_i \qquad ..(3.13)$$

Then, by substituting ΔP_m in (3.11) into (3.12)

$$P_m = P_m^0 + \sum_{i=1}^{NB} F_p(m.i)\ \Delta P_i + \sum_{i=1}^{NB} K_p(m.i)\,\Delta Q_i \qquad ..(3.14)$$

Since any changes in bus power injection cause variations in all bus voltage magnitudes and phase angles, $F_p(m.i)$ and $K_p(m.i)$ can be calculated as follows [73]:

$$F_p(m.i) = \sum_{k=1}^{NB} \frac{\partial|V_k|}{\partial P_i}\frac{\partial P_m}{\partial|V_k|} + \sum_{k=1}^{NB} \frac{\partial\delta_k}{\partial P_i}\frac{\partial P_m}{\partial\delta_k}$$

m = 1. 2. .... NL ... (3.15)

and

$$K_p(m.i) = \sum_{k=1}^{NB} \frac{\partial|V_k|}{\partial Q_i}\frac{\partial P_m}{\partial|V_k|} + \sum_{k=1}^{NB} \frac{\partial\delta_k}{\partial Q_i}\frac{\partial P_m}{\partial\delta_k}$$

m = 1. 2. .... NL ... (3.16)

Where, NL denotes the number of lines in the system.

The summation of the differential terms in (3.15) and (3.16) can be written as [73]:

$$F_p(m.i) = \left(\frac{\partial|V_i|}{\partial P_p}\right)\frac{\partial P_m}{\partial|V_i|} + \left(\frac{\partial|V_k|}{\partial P_p}\right)\frac{\partial P_m}{\partial|V_k|} + \left(\frac{\partial\delta_i}{\partial P_p}\right)\frac{\partial P_m}{\partial\delta_i} + \left(\frac{\partial\delta_k}{\partial P_p}\right)\frac{\partial P_m}{\partial\delta_k} \qquad \ldots (3.17)$$

$$K_p(m.i) = \left(\frac{\partial|V_i|}{\partial Q_p}\right)\frac{\partial P_m}{\partial|V_i|} + \left(\frac{\partial|V_k|}{\partial Q_p}\right)\frac{\partial P_m}{\partial|V_k|} + \left(\frac{\partial\delta_i}{\partial Q_p}\right)\frac{\partial P_m}{\partial\delta_i} + \left(\frac{\partial\delta_k}{\partial P_p}\right)\frac{\partial P_m}{\partial\delta_k} \qquad \ldots (3.18)$$

Where, $\frac{\partial|V_i|}{\partial P_p}, \frac{\partial|V_k|}{\partial P_p}, \frac{\partial\delta_i}{\partial P_p}$ and $\frac{\partial\delta_k}{\partial P_p}$ are the elements of JB3 and JB1, and $\frac{\partial|V_i|}{\partial Q_p}, \frac{\partial|V_k|}{\partial Q_p}, \frac{\partial\delta_i}{\partial Q_p}$ and $\frac{\partial\delta_k}{\partial Q_p}$ are the elements of JB4 and JB2, which can be obtained from equation (3.2) as:

$$\begin{bmatrix}\Delta\delta \\ \Delta|V|\end{bmatrix} = \begin{bmatrix} JB_1 & JB_2 \\ JB_3 & JB_4\end{bmatrix}\begin{bmatrix}\Delta P \\ \Delta Q\end{bmatrix}$$

Furthermore, by differentiating (3.9), the partial differential terms of $\frac{\partial P_m}{\partial|V_i|}, \frac{\partial P_m}{\partial|V_k|}, \frac{\partial P_m}{\partial\delta_i}$ and $\frac{\partial P_m}{\partial k}$ can be written as follows [73]:

$$\frac{\partial P_m}{\partial|V_i|} = 2\left|V_i^0\right|G_m - \left|V_k^0\right|G_m\cos\left(\delta_i^0 - \delta_k^0\right) - \left|V_k^0\right|B_m\sin\left(\delta_i^0 - \delta_k^0\right) \qquad ... (3.19)$$

$$\frac{\partial P_m}{\partial |V_k|} = -|V_i^0| G_m \cos(\delta_i^0 - \delta_k^0) - |V_i^0| B_m \sin(\delta_i^0 - \delta_k^0) \qquad \text{... (3.20)}$$

$$\frac{\partial P_m}{\partial \delta_i} = |V_i^0||V_k^0| G_m \sin(\delta_i^0 - \delta_k^0) - |V_i^0||V_k^0| B_m \cos(\delta_i^0 - \delta_k^0) \qquad \text{... (3.21)}$$

$$\frac{\partial P_m}{\partial \delta_k} = -|V_i^0||V_k^0| G_m \sin(\delta_i^0 - \delta_k^0) + |V_i^0||V_k^0| B_m \cos(\delta_i^0 - \delta_k^0) \qquad \text{... (3.22)}$$

Where, $|V_i^0|$, $|V_k^0|$, δ_i^0, δ_k^0 represent the voltage magnitude and the phase angle at bus p and bus q, in base case loading.

2). DG Output Curtailment

In the event of power flow congestion, the amount of generator power output required can be constrained using the following equation [75]:

$$\Delta DG_{p.m} = \frac{\Delta P_{i,k}}{\left(\frac{dP_{i,k}}{dDG_{p.m}}\right)} \qquad \text{..(3.23)}$$

Where $\Delta DG_{p,m}$ represents the amount of the DG real power output curtailment at node m. ΔP_{ik} represents the change in real power which is flowing from node i to node k, $\frac{dP_{ik}}{dGD_{p.m}}$ is the sensitivity factor, which expresses the relationship between the change in real power injection at node m with the change in power flow from node i to node k.

$\Delta P_{i,k}$, which represents the change in real power on the line between node p to node q, can be obtained from [75]:

$$\Delta P_{i,k} = \sqrt{(\propto S_{i,k}^{lim})^2 - ({''}Q_{i,k})^2} - \sqrt{({'}S_{i,k})^2 - ({'}Q_{i,k})^2} \qquad \text{..(3.24)}$$

Where $\propto$ is the target utilisation of the congested component, $S_{i,k}^{lim}$ is the thermal rating of the congested component, ${'}S_{i,k}$ is the initial apparent power flow of the line between node k and node k, ${'}Q_{i,k}$ is the initial reactive power flow of the line between node i and node k, ${''}Q_{i.k}$ is the target reactive power flowing from node i to node k. The term 'initial' refers to the condition before DG curtailment applied while the term 'target' refers to the condition after DG curtailment applied.

The above equation neglected the power losses. Considering that the power losses on distribution network are around 5%, the calculation of $\Delta P_{i,k}$ in this research also considers the power losses. Hence, equation (3.24) becomes:

$$\Delta P_{i,k} = \sqrt{\left(\propto S_{i,k}^{lim}\right)^2 - \left(''Q_{i,k}\right)^2} - \sqrt{\left('S_{i,k}\right)^2 - \left('Q_{i,k}\right)^2} + \sqrt{\left(P_{Loss-i,k}\right)^2 + \left(Q_{Loss-i,k}\right)^2} \quad ..(3.25)$$

Where $P_{Loss-i,k}$ is the initial active power losses between node i and node k and $Q_{Loss-i,k}$ is the initial reactive power losses between node i and node k.

Then, $\frac{dP_{ik}}{dGD_{p.m}}$ which represents the sensitivity factor for the change in real power injection of DG_p at node m with the change in power flow from node i to node k can be obtained from [75]:

$$\frac{dP_{ik}}{dDG_{p.m}} = F_p(m.i) + j\,K_p(m.i)$$

$$\frac{dP_{ik}}{dDG_{p.m}} = \left(\frac{\partial|V_i|}{\partial P_p}\right)\frac{\partial P_m}{\partial|V_i|} + \left(\frac{\partial|V_k|}{\partial P_p}\right)\frac{\partial P_m}{\partial|V_k|} + \left(\frac{\partial\delta_i}{\partial P_p}\right)\frac{\partial P_m}{\partial\delta_i} + \left(\frac{\partial\delta_k}{\partial P_p}\right)\frac{\partial P_m}{\partial\delta_k}$$

$$+ j\left(\left(\frac{\partial|V_i|}{\partial Q_p}\right)\frac{\partial P_m}{\partial|V_i|} + \left(\frac{\partial|V_k|}{\partial Q_p}\right)\frac{\partial P_m}{\partial|V_k|} + \left(\frac{\partial\delta_i}{\partial Q_p}\right)\frac{\partial P_m}{\partial\delta_i} + \left(\frac{\partial\delta_k}{\partial P_p}\right)\frac{\partial P_m}{\partial\delta_k}\right) \quad ..(3.26)$$

3). Energy Curtailment

Energy Curtailment of DG-p at bus m ($DG_{p,EnergyCurtail}$) can be calculated using the following equation [29]:

$$DG_{p,EnergyCurtail} = \Delta DG_{p.m} x DG_{p.cf} x DG_{p.oprtime} \quad ..(3.27)$$

Where, $\Delta G_{p.m}$ is the amount of DG-p output curtailment in MW, $DG_{p.cf}$ is the capacity factor of DG-p and $DG_{p.oprtime}$is the operation time of DG-p in hours. So, the unit of energy curtailment is in MWh.

4). Energy Curtailment Cost

Energy curtailment cost is the cost emerged as a result of curtailing energy output from DG. This cost will be borne by DG investors.

Energy Curtailment Cost of DG-p at bus m ($DG_{p,CurtailCost}$) can be derived by multiplying the energy curtailment of DG-p, which is expressed in MWh, with the levelised cost of energy generation of DG-p ($DG_{p.LCOEG}$), expressed in £/MWh [29]. Hence, the unit of energy curtailment cost is expressed in £.

$$DG_{p,CurtailCost} = DG_{p,EnergyCurtail} x DG_{p.LCOEG} \quad ..(3.28)$$

$$DG_{p,CurtailCost} = \Delta DG_{p.m} x DG_{p.cf} x DG_{p.oprtime} x DG_{p.LCOEG} \quad ..(3.29)$$

Where there are some DGs that must be curtailed at bus m. the total Energy Curtailment Cost ($EnCost_m$) is

$$EnCost_m = \sum_{p=1}^{k} DG_{p,EnergyCost} \quad ..(3.30)$$

$$EnCost_m = \sum_{p=1}^{k} \Delta DG_{p.m} x DG_{p.cf} x DG_{p.oprtime} x DG_{p.LCOEG} \quad ..(3.31)$$

B. Network Reinforcement Scheme

Besides DG curtailment scheme, another option to deal with the impact of DG connection at a generation-dominated busbar, i.e. when the network capacity is exceeded due to the new DG connection, is network reinforcement scheme. Network reinforcement scheme can be carried out by upgrading/reinforcing the capacity of the associated network components, such as lines, transformers and circuit breaker.

As shown in figure 3.11, a new DG connection requires a new infrastructure to be built between point of connection and point of supply. This connection might also require the existing network/line must be reinforced to accommodate additional DG capacity.

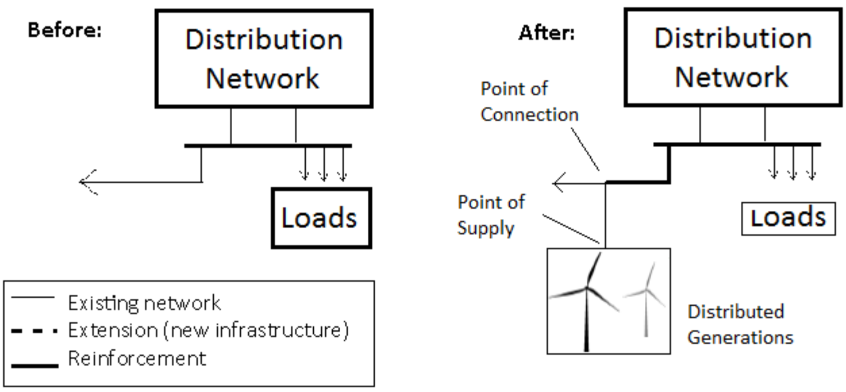

Figure 3.11 A New DG Connection at a Distribution Network [76]

The new infrastructure and the required reinforcement cause two main cost components in network reinforcement scheme, i.e. the sole-use connection assets and the shared-use connection assets [77][78]. The first cost component will be directly passed on to the customer since the assets are merely be used by that customer. While the second one becomes system assets, i.e. the assets will be used by all customers connected to that particular line. Table 3.11 represents an example of costs components of DG connection.

	Cost Components
Sole-Use Connection Assets	Feasibility Studies
	Assessment and Design for all relevant work
	Assessment and Design of the Non-Contestable Work
	Design Approval of the Contestable Work
	Final Works and Phased Energisation
	Inspection and Monitoring - HV Network Site Visit
	Land Rights
	Installation of a 500m HV cable
	HV circuit Breaker at customer substation with suitable protection
	Actuators and Remote Control (RTU)
Shared-Use Connection Assets	2 HV Circuit Breakers at Primary substation
	Re-conductor of a 3000m HV overhead line
	Replacement of existing 11 panel 11kV switchgear
	Installation of a 500m HV cable
	Replace two 60MVA, 132/33kV transformers with two 90MVA transformers.

Table 3.11 Cost Components of DG Connection [77][78]

Since the sole-use connection assets costs has been directly passed on the customers who seek for connection, the amount of investment cost will be based on the shared-use connection assets costs only.

A. Network Reinforcement Cost vs DG Curtailment Cost

Costs comparison between network reinforcement scheme and DG curtailment scheme is needed to decide whether network reinforcement or DG curtailment is a more worthy choice. In terms of financial expenses, the lower cost the better option. This means that the network reinforcement cost must be higher than or, at least equal to, the maximum DG curtailment cost.

1). Maximum DG Output Curtailment

The maximum DG output curtailment is calculated based on the assumption that DG energy curtailment cost is equal to the required reinforcement cost.

By assuming that the network reinforcement cost, $InvCost_m$, is equal to the DG curtailment cost, $EnCost_m$, the maximum output of DG_p to be curtailed, $\Delta DGmax_{p.m}$, can be calculated as follows [79]:

If $InvCost_m = EnCost_m$; $\Delta DG_{p.m} = \Delta DGmax_{p.m}$, from equation (3.31),

$$\Delta DGmax_{p.m} = \frac{InvCost_m}{DG_{p.cf} x DG_{p.oprtime} x DG_{p.LCOEG}} \quad \text{... (3.32)}$$

Where

$EnCost_p$ = Energy Curtailment Cost of DG_p (£)

$InvCost_m$ = Investment Cost to reinforce line –m (£)

$DG_{p.cf}$ = capacity factor of DG_p

$DG_{p.oprtime}$ = annual operational time of DG_p (hours)

$DG_{p.LCOEG}$ = levelised cost of energy generation of DG_p (£/MWh)

$\Delta DG_{p.m}$ = required out put of DG_p to be curtailed (MW)

$\Delta DGmax_{p.m}$ = maximum out put of DG_p to be curtailed (MW)

Given the maximum DG output curtailment, $\Delta Gmax_{p.m}$, the amount of energy curtailment at this point can be calculated using the following equation:

$$DG_{p,EnergyCurtailMax} = \Delta DGmax_{p.m} x DG_{p.cf} x DG_{p.oprtime} \quad \text{... (3.33)}$$

2). Energy Conveyed from the New Connected DG

By assuming that the standard capacity of the network or the line is $S_{i.k}^{lim}$, the apparent power flowing through the line before the connection is $S_{i.k}$, and the line power losses before the connection is $S_{Losses-i.k}$, the available network capacity prior to DG connection can be calculated using:

$$Line_{ik,capacity} = \left(\frac{dP_{ik}}{dDG_{p.m}}\right) * (S_{i.k}^{lim} - S_{i.k} + S_{Losses-i.k}) \quad \text{... (3.34)}$$

Where, $\frac{dP_{ik}}{dGD_{p.m}}$ is the sensitivity factor for the change in real power injection of DG_p at node m with the change in power flow from node i to node k, as shown in equation (3.26). Therefore, the amount of energy conveyed through the network from the new connected DG, without network reinforcement, can be obtained from:

$$\text{EnConvey}_{p}^{m} = \text{Line}_{ik,capacity} * \text{DG}_{p.pf} * \text{DG}_{p.cf} * \text{DG}_{p.oprtime} \qquad ...(3.35)$$

3). The Minimum Requirement for Energy to be Conveyed

The minimum requirement for energy to be conveyed from the new connected DG, Energy_{req}, can be obtained by considering the amount of maximum DG energy can be conveyed without network reinforcement, EnConvey_{p}^{m}, and the amount of maximum DG energy curtailment, EnCur_{p}^{m}, in 1 year period (8760 hours) [79].

$$\text{DG}_{p,EnergyReq} = \text{DG}_{p,EnergyCurtailMax} + \text{EnConvey}_{p}^{m} \qquad \dots(3.36)$$

$$\text{DG}_{p,EnergyReq} = \left(\Delta\text{DGmax}_{p.m} + \left(\frac{dP_{ik}}{dDG_{p.m}}\right) * \left(S_{i.k}^{lim} - S_{i.k} + S_{Losses-i.k}\right) * \text{DG}_{p.pf}\right) * \text{DG}_{p.cf} * 8760 \qquad \dots(3.37)$$

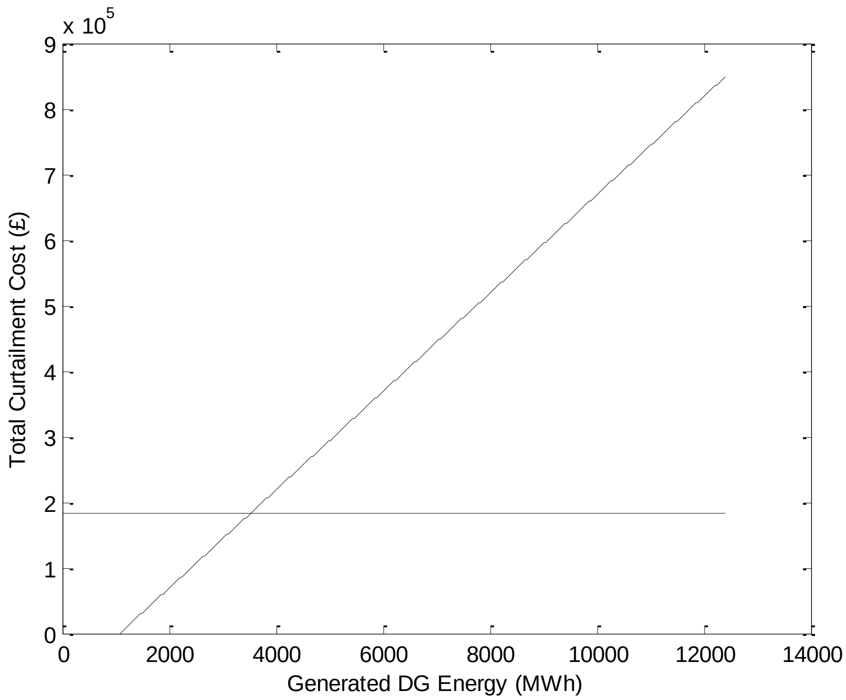

Figure 3.12 Cross Section between Curtailment Cost and Reinforcement Cost

Figure 3.12 shows the cross section between DG output Curtailment Cost and Network Reinforcement Cost. The horizontal line shows the network reinforcement cost and the linear curve shows the energy curtailment cost. The cross section point indicates the network reinforcement cost has the same value with the energy curtailment cost.

This means that below this point, the energy curtailment cost is less than the network reinforcement cost. This also means that starting from this point and beyond, the energy curtailment cost is higher than the network reinforcement cost.

The comparison of DG curtailment cost and Network Reinforcement cost will lead to the decision which scheme is better, in terms of cost, i.e. the lower the cost the better.

3.2 IMPACT OF DEMAND SIDE RESPONSE ON NETWORK PERFORMANCE

As described in section 2.3.1, Demand Side Response can be defines as a deliberate act of end user, either as an individual or a group, to change their demand in response to energy market price or the signals of congested network [15].

In this section, the impact of DSR on the performance of distribution network in terms of voltage level, network capacity utilization, and power losses, is examined by considering the response of end users to congested network through demand reduction, demand shifting and running on-site generation.

3.2.1 DSR Mechanisms

There are three DSR mechanisms examined in this thesis, i.e. demand reduction, demand shifting and running on-site generation mechanisms.

Demand reduction mechanism is a mechanism to reduce electricity demand following an outage on the network in order to avoid further failure. In this case, the demand from the participated customers will be reduced when a particular line, i.e. the line between Bus11-4 and Bus11-7, is out of service.

Demand shifting mechanism is a mechanism to shift electricity consumption from peak times to off-peak times of the day. In this case, the customers who participate in DSR programme are willing to shift their electricity consumption during peak times (in the evening) to other off-peak times of the day, for one hour period.

Running on-site generation is a mechanism to operate generations which are installed and owned by end users. In this case, this mechanism is applied in response to supply scarcity due to one of DGs on the network, i.e. DG3 with the capacity of 6.5MVA, is out of service.

3.2.2 DSR Participation

Another important factor in examining the impact of DSR is related to the participation of end user in DSR programme. Assuming that the participation of consumers in the DSR programme implemented on the network in figure 3.13 is given in table 3.12.

Type of DSR	**Type of Customers**	**Name**	**DSR Capacity (MW)**
Demand Reduction	Industrial/Commercial	MD1	0.30
		MD2	0.30
		MD3	0.30
		MD4	0.30
		MD5	0.30
Sub Total			1.50
On-site Generation	Industrial/Commercial	MD1	0.20
		MD2	0.20
		MD3	0.20
		MD4	0.20
		MD5	0.20
Sub Total			1.00
Load Shifting	Household	LD1	0.15
		LD2	0.15
		LD3	0.15
Sub Total			0.45

Table 3.12 DSR Participation

Table 3.12 shows the total available DSR capacity from customers who participate in DSR programme. There are five industrial/commercials customers, i.e. MD1, MD2, MD3, MD4 and MD5, who participate in demand reduction DSR with total contribution of 1.5MW. These customers also install on-site generations with total capacity of 1MW. While three groups of household customers, i.e. LD1, LD2 and LD3, participate in load shifting DSR with total capacity of 0.45MW.

3.2.3 DSR with Demand Reduction Mechanism

The first mechanism of DSR implementation is demand reduction mechanism, i.e. demand side response which is done by reducing the use of electricity by consumers. This mechanism can be investigated through the case where a failure occurs on a particular line of the network.

For instance, an outage occurs at the power line between Bus11-4 and Bus11-7. This is indicated by the absence of the power flow on that line, as depicted in figure 3.13. This failure will cause the line’s capacity between Bus11-8 and Bus11-9 is exceeded.

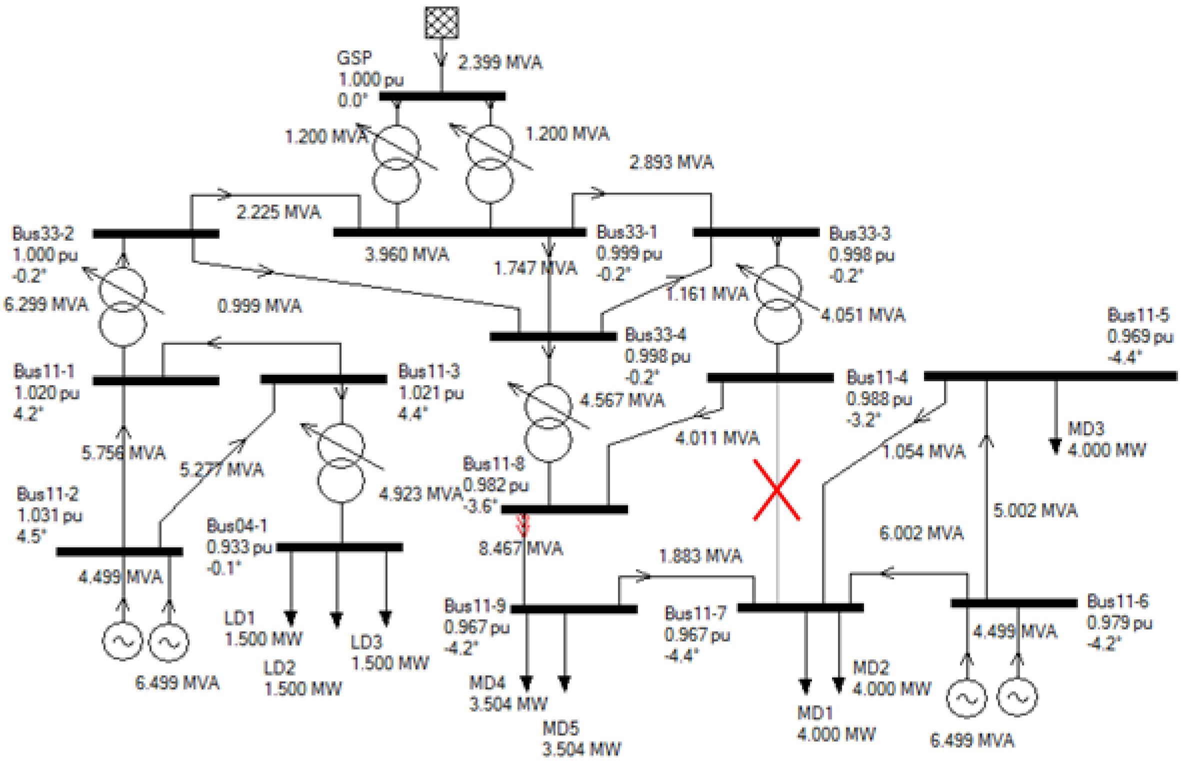

Figure 3.13 Load Flow Results Following a Line Outage

To deal with this condition, i.e. avoiding further network failure, the DNO can require the customers, who participate in Demand Reduction DSR programme, to reduce their electricity consumption. As presented in table 3.15, the total of 1.5MW capacity can be participated in demand reduction DSR.

The impact of demand reduction on the network performance is depicted in figure 3.13. The details, including the impact on voltage level, power flow and power losses, are presented in table 3.13, 3.14 and 3.15, respectively.

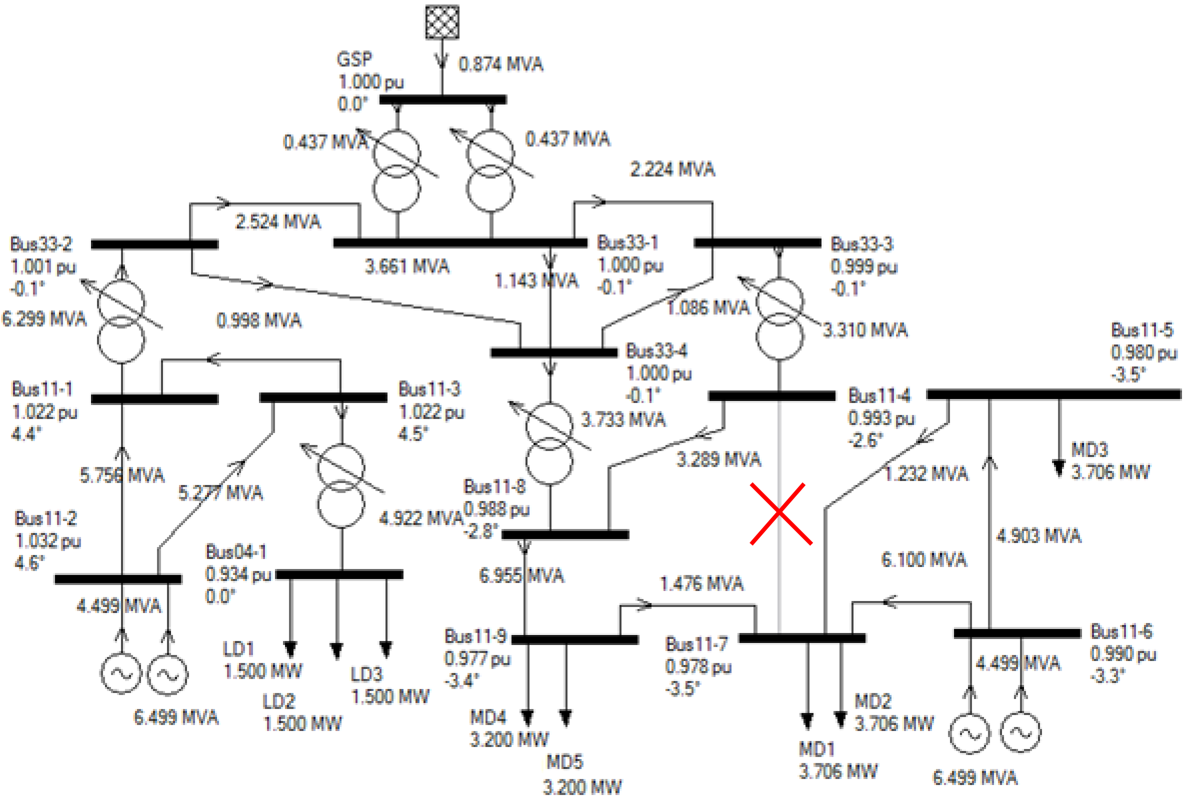

Figure 3.14 Demand Reduction after a Line Outage

Bus Name	Initial Network		Line Outage		
	Voltage Mag (pu)	Voltage Angle (deg)	Voltage Mag (pu)	Voltage Angle (deg)	dV
GSP	1		1		0.0%
Bus33-1	0.999	-0.2	0.999	-0.21	0.0%
Bus33-2	1	-0.18	1	-0.19	0.0%
Bus11-1	1.02	4.25	1.02	4.25	0.0%
Bus11-2	1.031	4.51	1.031	4.5	0.0%
Bus11-3	1.021	4.37	1.021	4.36	0.0%
Bus04-1	0.933	-0.1	0.933	-0.11	0.0%
Bus33-4	0.999	-0.21	0.998	-0.22	-0.1%
Bus11-8	0.985	-3.37	0.982	-3.55	-0.3%
Bus11-9	0.977	-3.69	0.967	-4.17	-1.0%
Bus33-3	0.998	-0.22	0.998	-0.23	0.0%
Bus11-4	0.987	-3.35	0.988	-3.25	0.1%
Bus11-7	0.981	-3.63	0.967	-4.4	-1.4%
Bus11-5	0.983	-3.63	0.969	-4.4	-1.4%
Bus11-6	0.993	-3.42	0.979	-4.18	-1.4%

Table 3.13 Impact of Line Outage on Voltage Level

In this case, the line between Bus11-4 and Bus11-7 is out of service. This outage causes the voltage level of Bus11-4 to increase by 0.1% from the initial level. This is because the line outage reduces the demand connected to Bus11-4. As the result of demand reduction, the voltage level will increase.

Contrary, the line outage will reduce the supply to the demand connected at Bus11-7. As the result of supply reduction, which also means the reduction in power generation, the voltage level at Bus11-7 will decrease by 1.4% from the initial level.

Bus Name	Line Outage		Demand Reduction		
	Voltage Mag (pu)	**Voltage Angle (deg)**	**Voltage Mag (pu)**	**Voltage Angle (deg)**	**dV**
GSP	1		1		0.0%
Bus33-1	0.999	-0.21	1	-0.08	0.1%
Bus33-2	1	-0.19	1.001	-0.06	0.1%
Bus11-1	1.02	4.25	1.022	4.37	0.2%
Bus11-2	1.031	4.5	1.032	4.62	0.1%
Bus11-3	1.021	4.36	1.022	4.48	0.1%
Bus04-1	0.933	-0.11	0.934	0.02	0.1%
Bus33-4	0.998	-0.22	1	-0.09	0.2%
Bus11-8	0.982	-3.55	0.988	-2.83	0.6%
Bus11-9	0.967	-4.17	0.977	-3.35	1.0%
Bus33-3	0.998	-0.23	0.999	-0.1	0.1%
Bus11-4	0.988	-3.25	0.993	-2.57	0.5%
Bus11-7	0.967	-4.4	0.978	-3.53	1.1%
Bus11-5	0.969	-4.4	0.98	-3.52	1.1%
Bus11-6	0.979	-4.18	0.99	-3.31	1.1%

Table 3.14 Impact of Demand Reduction on Voltage Level

The outage of the line between Bus11-4 and Bus11-7 will cause another failure on the network, i.e. the power flow on the line between Bus11-8 and Bus11-9 is exceeding its standard capacity. To deal with this problem, the customers who are participating in DSR programme are required to reduce their energy consumption. As presented in table 3.14, the demand reduction causes the voltage level of the related busbars to increase by around 1.1% from the initial level.

rom Busbar	To Busbar	Standard Rating (MVA)	Network Capacity Utilization					
			Initial Network		Line Outage		Demand Reduction	
GSP	Bus33-1	40.000	1.150	2.9%	1.200	3.0%	0.437	1.1%
GSP	Bus33-1	40.000	1.150	2.9%	1.200	3.0%	0.437	1.1%
Bus33-2	Bus33-1	15.433	2.269	14.7%	2.225	14.4%	2.524	16.4%
Bus33-2	Bus11-1	10.000	6.299	63.0%	6.299	63.0%	6.299	63.0%
Bus11-1	Bus11-2	7.049	5.756	81.7%	5.756	81.7%	5.756	81.7%
Bus11-1	Bus11-3	7.049	0.998	14.2%	0.999	14.2%	0.998	14.2%
Bus11-3	Bus04-1	7.500	4.923	65.6%	4.923	65.6%	4.922	65.6%
Bus33-4	Bus11-8	10.000	4.292	42.9%	4.567	45.7%	3.733	37.3%
Bus11-8	Bus11-9	7.049	4.908	69.6%	8.467	120.1%	6.955	98.7%
Bus33-1	Bus33-4	15.433	1.653	10.7%	1.747	11.3%	1.143	7.4%
Bus33-1	Bus33-3	15.433	2.932	19.0%	2.893	18.7%	2.224	14.4%
Bus33-3	Bus11-4	10.000	4.218	42.2%	4.051	40.5%	3.310	33.1%
Bus11-3	Bus11-2	7.049	5.277	74.9%	5.277	74.9%	5.277	74.9%
Bus11-4	Bus11-8	7.049	0.714	10.1%	4.011	56.9%	3.289	46.7%
Bus33-3	Bus33-4	15.433	1.286	8.3%	1.161	7.5%	1.086	7.0%
Bus33-2	Bus33-4	15.433	3.915	25.4%	3.960	25.7%	3.661	23.7%
Bus11-5	Bus11-7	7.049	1.055	15.0%	1.054	15.0%	1.232	17.5%
Bus11-9	Bus11-7	7.049	2.236	31.7%	1.883	26.7%	1.476	20.9%
Bus11-4	Bus11-7	7.049	3.520	49.9%				
Bus11-7	Bus11-6	7.049	6.002	85.1%	6.002	85.1%	6.100	86.5%
Bus11-5	Bus11-6	7.049	5.002	71.0%	5.002	71.0%	4.903	69.6%

Table 3.15 Impact of Line Outage and Demand Reduction on Power Flow

As presented in table 3.15, the line outage significantly increases the power flowing through the line between Bus11-8 and Bus11-9. This power flow exceeds the standard rating of the line by 120.1%. Then, after demand reduction mechanism is applied, the power flowing through this line decrease down to 98.7% of the standard rating, avoiding further outage on the network.

From Busbar	To Busbar	Power Losses						
		Initial Network			Line Outage			
		(MW)	(MVAr)	(MVA)	(MW)	(MVAr)	(MVA)	dSlosses
GSP	Bus33-1	0	0.004	0.004	0	0.004	0.004	0.0%
GSP	Bus33-1	0	0.004	0.004	0	0.004	0.004	0.0%
Bus33-2	Bus33-1	0.002	-0.054	0.054	0.002	-0.054	0.054	0.0%
Bus33-2	Bus11-1	0.028	0.498	0.499	0.028	0.498	0.499	0.0%
Bus11-1	Bus11-2	0.046	0.031	0.055	0.046	0.031	0.055	0.0%
Bus11-1	Bus11-3	0.001	-0.013	0.013	0.001	-0.013	0.013	0.0%
Bus11-3	Bus04-1	0.096	0.552	0.560	0.097	0.552	0.560	0.0%
Bus33-4	Bus11-8	0.013	0.242	0.242	0.015	0.274	0.274	13.2%
Bus11-8	Bus11-9	0.036	0.023	0.043	0.109	0.095	0.145	238.5%
Bus33-1	Bus33-4	0.001	-0.054	0.054	0.001	-0.054	0.054	0.0%
Bus33-1	Bus33-3	0.003	-0.053	0.053	0.003	-0.053	0.053	0.0%
Bus33-3	Bus11-4	0.013	0.234	0.234	0.012	0.215	0.215	-8.1%
Bus11-3	Bus11-2	0.038	0.024	0.045	0.038	0.024	0.045	0.0%
Bus11-4	Bus11-8	0.001	-0.013	0.013	0.024	0.011	0.026	102.5%
Bus33-3	Bus33-4	0.001	-0.054	0.054	0	-0.054	0.054	0.0%
Bus33-2	Bus33-4	0.005	-0.052	0.052	0.005	-0.052	0.052	0.0%
Bus11-5	Bus11-7	0.002	-0.012	0.012	0.002	-0.011	0.011	-8.1%
Bus11-9	Bus11-7	0.008	-0.006	0.010	0.006	-0.007	0.009	-7.8%
Bus11-4	Bus11-7	0.019	0.005	0.020				
Bus11-7	Bus11-6	0.053	0.04	0.066	0.055	0.042	0.069	4.2%
Bus11-5	Bus11-6	0.037	0.023	0.044	0.038	0.025	0.045	4.4%
Total Losses		0.403	1.369	1.427	0.482	1.477	1.554	8.9%

Table 3.16 Impact of Line Outage on Power Losses

The failure of the line between Bus11-4 and Bus11-7 causes the increase of the power losses on particular lines but it decreases the power losses of other lines on the network. As seen in table 3.16, the power losses of the line between Bus11-4 and Bus11-8 increases by 102.5%, while the power losses of the line between Bus11-8 and Bus11-9 increases by 238.5% from the initial level. The increase of power losses due to additional power, which is previously flowing through the failed line, will flow through these lines. As the power increased, the power losses will increase as well.

From Busbar	To Busbar	Power Losses						
		Line Outage			Demand Reduction			
		(MW)	(MVAr)	(MVA)	(MW)	(MVAr)	(MVA)	dSlosses
GSP	Bus33-1	0	0.004	0.004	0	0.001	0.001	-75.0%
GSP	Bus33-1	0	0.004	0.004	0	0.001	0.001	-75.0%
Bus33-2	Bus33-1	0.002	-0.054	0.054	0.002	-0.054	0.054	0.0%
Bus33-2	Bus11-1	0.028	0.498	0.499	0.027	0.497	0.498	-0.2%
Bus11-1	Bus11-2	0.046	0.031	0.055	0.045	0.031	0.055	-1.5%
Bus11-1	Bus11-3	0.001	-0.013	0.013	0.001	-0.013	0.013	0.0%
Bus11-3	Bus04-1	0.097	0.552	0.560	0.096	0.55	0.558	-0.4%
Bus33-4	Bus11-8	0.015	0.274	0.274	0.01	0.182	0.182	-33.6%
Bus11-8	Bus11-9	0.109	0.095	0.145	0.072	0.058	0.092	-36.1%
Bus33-1	Bus33-4	0.001	-0.054	0.054	0	-0.055	0.055	1.8%
Bus33-1	Bus33-3	0.003	-0.053	0.053	0.002	-0.054	0.054	1.8%
Bus33-3	Bus11-4	0.012	0.215	0.215	0.008	0.143	0.143	-33.5%
Bus11-3	Bus11-2	0.038	0.024	0.045	0.038	0.023	0.044	-1.2%
Bus11-4	Bus11-8	0.024	0.011	0.026	0.016	0.002	0.016	-38.9%
Bus33-3	Bus33-4	0	-0.054	0.054	0	-0.055	0.055	1.9%
Bus33-2	Bus33-4	0.005	-0.052	0.052	0.004	-0.052	0.052	-0.2%
Bus11-5	Bus11-7	0.002	-0.011	0.011	0.002	-0.011	0.011	0.0%
Bus11-9	Bus11-7	0.006	-0.007	0.009	0.003	-0.01	0.010	13.2%
Bus11-4	Bus11-7							
Bus11-7	Bus11-6	0.055	0.042	0.069	0.056	0.042	0.070	1.2%
Bus11-5	Bus11-6	0.038	0.025	0.045	0.036	0.022	0.042	-7.2%
Total Losses		0.482	1.477	1.554	0.418	1.248	1.316	-15.3%

Table 3.17 Impact of Demand Reduction on Power Losses

Following the failure on the line between Bus11-4 and Bus11-7, the customers who participate in DSR programme are required to reduce their demand. As presented in table 3.17, demand reduction mechanism will reduce the power losses of the line between Bus11-4 and Bus11-8, and of the line between Bus11-8 and Bus11-9 by 38.9% and 36.1%, respectively. As the demand reduced, the amount of power to supply the demand will decrease, which in turn, it will decrease the power losses. This reduction is calculated based on the level of power losses at the event of failure.

3.2.4 DSR with Demand Shifting Mechanism

Demand Shifting is a mechanism in DSR programme to shift the electricity consumption from peak times to off-peak times. So, the customers do not reduce their total electricity consumption but they change the time to consume electricity. This will reduce the peak demand and increase electricity consumption during off-peak time, which in turn, it will flatten or smoothen the load profile.

In electricity market, where time off use (TOU) tariffs or dynamic pricing has been implemented, consumers who shift their consumption from peak to off-peak times will benefit for paying less bills with the same amount of electricity consumption, since the price during off-peak is lower than peak times [49].

Peak demand will force system components to run on its maximum capacity. At some points, it might cause the system needs to be upgraded to fulfil the demand. Therefore, demand shifting which flatten the peak demand and move it to other off-peak times during the day can avoid or defer network reinforcement.

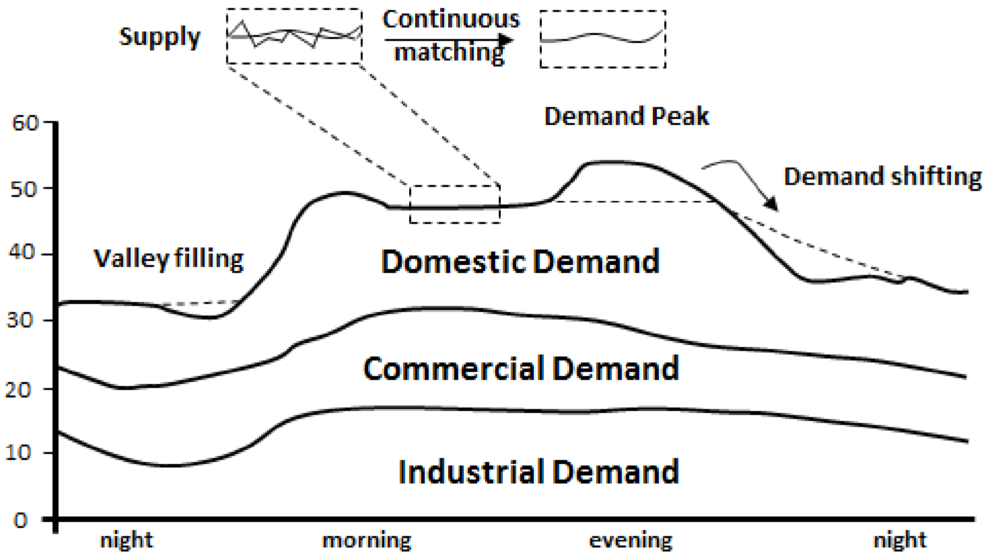

Figure 3.15 Impact of Demand Shifting on Load Profile [49]

As seen in figure 3.15, the peak demand during evening is moved to off-peak times during night. It also can be done by filling the valley where the electricity consumption is quite low. Domestic customers contribute the most in demand shifting due to their flexibility in electricity consumption. Some of their household appliances, such as storage heaters, washing machines and dishwashers can be operated during off-peak instead of peak times. This mechanism requires customers to change their behaviour which might cause some inconvenience but, in turn, they will benefit for paying less electricity bills for the same usage.

In the UK, domestic customers contribute around 0.25 GW in demand shifting through storage heaters which are automatically operated at night. The implementation of lower prices, such as Economy 7 tariffs, has encouraged customers to shift approximately 20% of their annual demand from the day to the night [49].

3.2.5 DSR with Running On-Site Generation Mechanism

Another DSR mechanism is on-site generation. On-site generation is generation that is installed either by industrial, commercial or household sectors as stand-by generator to back up the electricity supply when generation scarcity occurs in the distribution system due to power line's failure or DG outage.

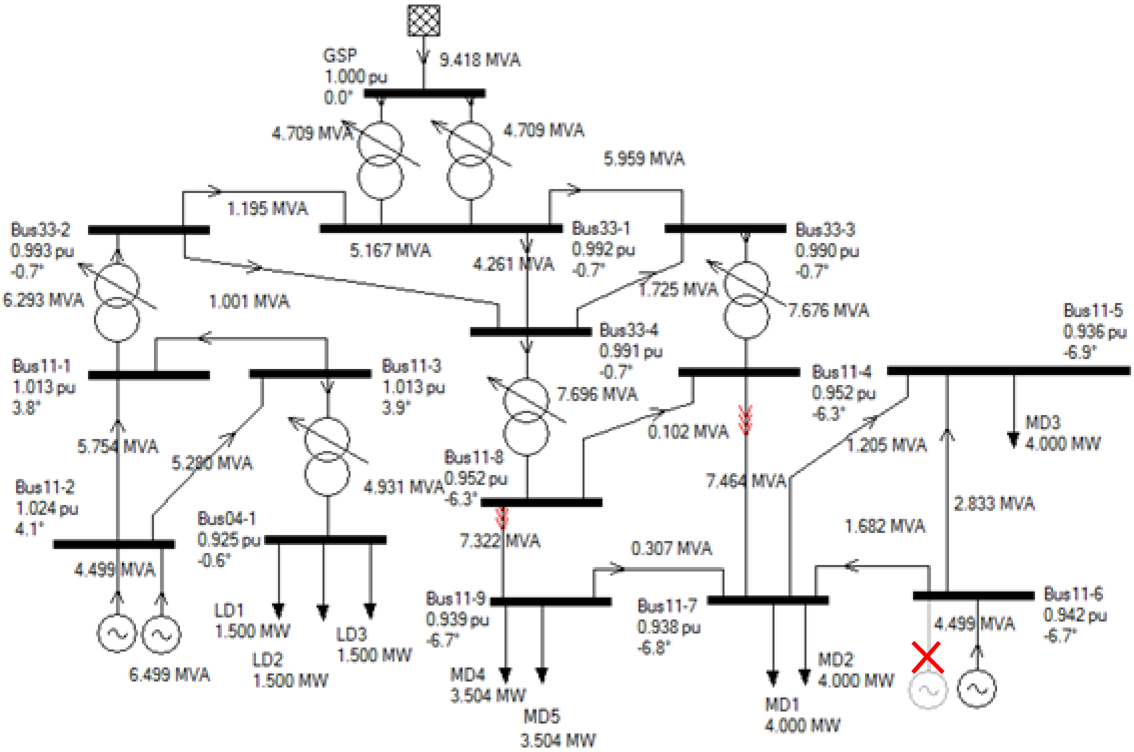

Figure 3.16 Load Flow Results Following a DG Outage

As shown in figure 3.16, the outage of DG4 which is connected to Bus11-6 will cause the capacity of the line between Bus11-4 and Bus11-7, is exceeded. The power flow increases up to 7.322 MVA, exceeding the rating capacity of 7.049 MVA.

To deal with this condition, i.e. avoiding another failure occurs in the system, the DNO can require the customers to run their on-site generations which act as stand-by reserve. As presented in table 3.15, each industrial customer has installed on-site generation with the capacity of 0.2 MVA. When required by the DNO, all industrial customers can provide reserve generation capacity of 1 MVA. By running on-site generation at Bus11-7, following DG outage at Bus11-6, the power flowing through the line between Bus11-4 and Bus11-7 decreases, so the line capacity is not exceeded anymore. The impact of running on-site generation is depicted in figure 3.17 and the details are presented in table 3.18, 3.19 and 3.20, respectively.

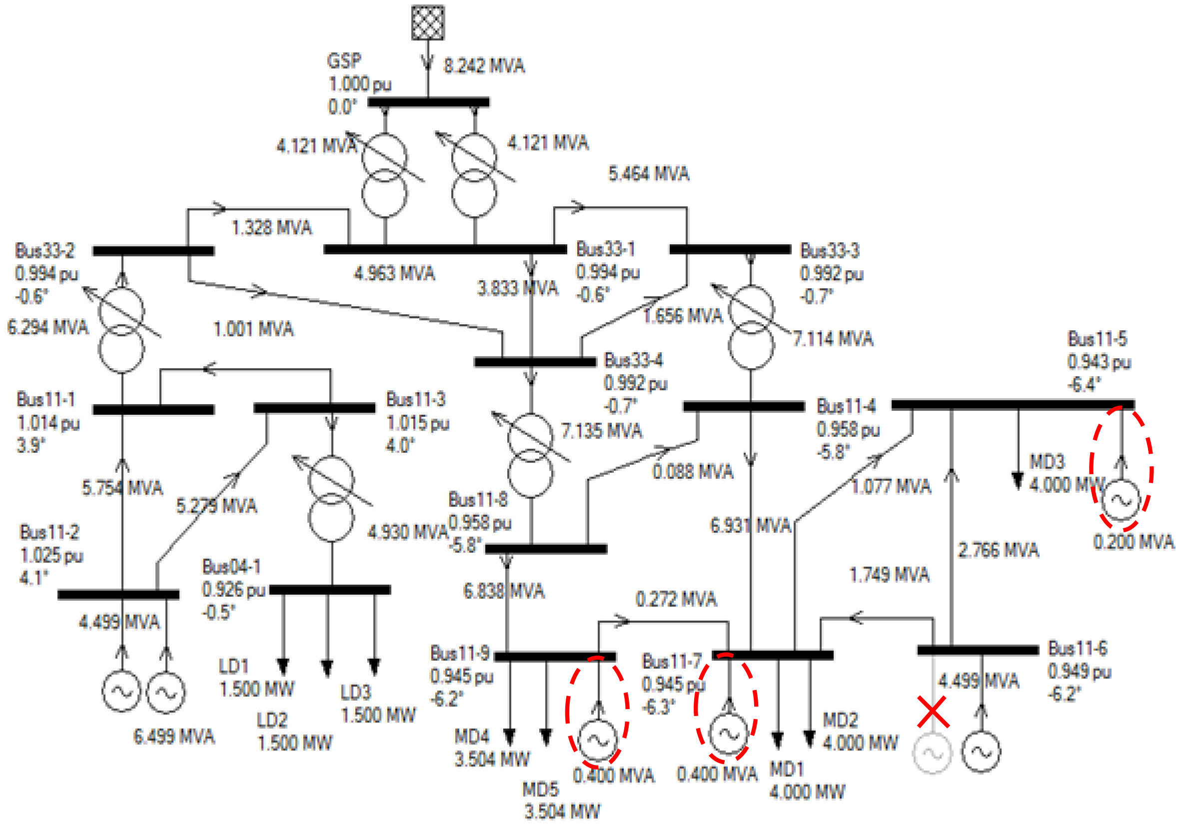

Figure 3.17 Running on-site Generation after a DG Outage

Bus Name	Initial Network		DG Outage		
	Voltage Mag (pu)	Voltage Angle (deg)	Voltage Mag (pu)	Voltage Angle (deg)	dV
GSP	1		1		0.0%
Bus33-1	0.999	-0.2	0.992	-0.72	-0.7%
Bus33-2	1	-0.18	0.993	-0.7	-0.7%
Bus11-1	1.02	4.25	1.013	3.8	-0.7%
Bus11-2	1.031	4.51	1.024	4.06	-0.7%
Bus11-3	1.021	4.37	1.013	3.91	-0.8%
Bus04-1	0.933	-0.1	0.925	-0.63	-0.9%
Bus33-4	0.999	-0.21	0.991	-0.73	-0.8%
Bus11-8	0.985	-3.37	0.952	-6.29	-3.4%
Bus11-9	0.977	-3.69	0.939	-6.75	-3.9%
Bus33-3	0.998	-0.22	0.99	-0.74	-0.8%
Bus11-4	0.987	-3.35	0.952	-6.31	-3.5%
Bus11-7	0.981	-3.63	0.938	-6.79	-4.4%
Bus11-5	0.983	-3.63	0.936	-6.88	-4.8%
Bus11-6	0.993	-3.42	0.942	-6.74	-5.1%

Table 3.18 Impact of DG Outage on Voltage Level

At the event of a failure, i.e. when a DG at Bus11-6 is out of service, the voltage level of some busbars will decrease. As seen in table 3.18, the decrease of voltage level is in the range between 3.4% until 5.1% from the initial level. The highest voltage reduction occurs at the busbar where the DG outage taken place.

Name	DG Outage		Running On-site Generation		
	Voltage Mag (pu)	Voltage Angle (deg)	Voltage Mag (pu)	Voltage Angle (deg)	dV
GSP	1		1		0.0%
Bus33-1	0.992	-0.72	0.994	-0.64	0.2%
Bus33-2	0.993	-0.7	0.994	-0.62	0.1%
Bus11-1	1.013	3.8	1.014	3.87	0.1%
Bus11-2	1.024	4.06	1.025	4.13	0.1%
Bus11-3	1.013	3.91	1.015	3.98	0.2%
Bus04-1	0.925	-0.63	0.926	-0.55	0.1%
Bus33-4	0.991	-0.73	0.992	-0.65	0.1%
Bus11-8	0.952	-6.29	0.958	-5.82	0.6%
Bus11-9	0.939	-6.75	0.945	-6.24	0.6%
Bus33-3	0.99	-0.74	0.992	-0.66	0.2%
Bus11-4	0.952	-6.31	0.958	-5.83	0.6%
Bus11-7	0.938	-6.79	0.945	-6.28	0.7%
Bus11-5	0.936	-6.88	0.943	-6.37	0.7%
Bus11-6	0.942	-6.74	0.949	-6.23	0.7%

Table 3.19 Impact of Running On-site Generation on Voltage Level

In order to deal with the supply scarcity on the network, due to one of the DGs connected to Bus11-6 is out of service, the DSR participants are required to run their on-site generations. This mechanism causes the voltage level of some busbars to increase in the range between 0.6% and 0.7%, compared with the voltage level at the event of failure, as presented in table 3.19.

From Busbar	To Busbar	Standard Rating (MVA)	Network Capacity Utilization					
			Initial Network		DG Outage		On-site Generation	
GSP	Bus33-1	40.000	1.150	2.9%	4.709	11.8%	4.121	10.3%
GSP	Bus33-1	40.000	1.150	2.9%	4.709	11.8%	4.121	10.3%
Bus33-2	Bus33-1	15.433	2.269	14.7%	1.196	7.7%	1.328	8.6%
Bus33-2	Bus11-1	10.000	6.299	63.0%	6.293	62.9%	6.294	62.9%
Bus11-1	Bus11-2	7.049	5.756	81.7%	5.754	81.6%	5.754	81.6%
Bus11-1	Bus11-3	7.049	0.998	14.2%	1.001	14.2%	1.001	14.2%
Bus11-3	Bus04-1	7.500	4.923	65.6%	4.931	65.7%	4.930	65.7%
Bus33-4	Bus11-8	10.000	4.292	42.9%	7.696	77.0%	7.135	71.4%
Bus11-8	Bus11-9	7.049	4.908	69.6%	7.322	103.9%	6.838	97.0%
Bus33-1	Bus33-4	15.433	1.653	10.7%	4.261	27.6%	3.833	24.8%
Bus33-1	Bus33-3	15.433	2.932	19.0%	5.959	38.6%	5.464	35.4%
Bus33-3	Bus11-4	10.000	4.218	42.2%	7.676	76.8%	7.114	71.1%
Bus11-3	Bus11-2	7.049	5.277	74.9%	5.280	74.9%	5.279	74.9%
Bus11-4	Bus11-8	7.049	0.714	10.1%	0.102	1.4%	0.088	1.2%
Bus33-3	Bus33-4	15.433	1.286	8.3%	1.725	11.2%	1.656	10.7%
Bus33-2	Bus33-4	15.433	3.915	25.4%	5.167	33.5%	4.963	32.2%
Bus11-5	Bus11-7	7.049	1.055	15.0%	1.205	17.1%	1.077	15.3%
Bus11-9	Bus11-7	7.049	2.236	31.7%	0.307	4.4%	0.272	3.9%
Bus11-4	Bus11-7	7.049	3.520	49.9%	7.464	105.9%	6.931	98.3%
Bus11-7	Bus11-6	7.049	6.002	85.1%	1.682	23.9%	1.749	24.8%
Bus11-5	Bus11-6	7.049	5.002	71.0%	2.833	40.2%	2.766	39.2%

Table 3.20 Impact of DG Outage and On-site Generation on Network Capacity Utilization

As shown in table 3.20, the failure of a DG connected to Bus11-6 can cause the power flow on the line between Bus11-4 and Bus11-7 will exceed the standard rating by 105.9%. This connection also increases the power flow on the line between Bus11-8 and Bus11-9 by 103.9%.

To avoid further failures, the on-site generations connected to Bus11-9, Bus11-7 and Bus11-5 are operated. The power generated from on-site generations can be used to replace the lost power from the failed DG at Bus11-6. As presented in table 3.20, the operation of on-site generation can reduce the network capacity utilization of the line between Bus 11-8 and Bus11-9, from 104.9% down to 97.0%. On the line between Bus11-4 and Bus11-7, the network capacity utilization decreases from 105.9% down to 98.3%.

From Busbar	To Busbar	Power Losses						
		Initial Network			DG Outage			
		(MW)	(MVAr)	(MVA)	(MW)	(MVAr)	(MVA)	dSlosses
GSP	Bus33-1	0	0.004	0.004	0.003	0.069	0.069	1626.6%
GSP	Bus33-1	0	0.004	0.004	0.003	0.069	0.069	1626.6%
Bus33-2	Bus33-1	0.002	-0.054	0.054	0	-0.054	0.054	-0.1%
Bus33-2	Bus11-1	0.028	0.498	0.499	0.028	0.505	0.506	1.4%
Bus11-1	Bus11-2	0.046	0.031	0.055	0.046	0.032	0.056	1.0%
Bus11-1	Bus11-3	0.001	-0.013	0.013	0.001	-0.013	0.013	0.0%
Bus11-3	Bus04-1	0.096	0.552	0.560	0.098	0.562	0.570	1.8%
Bus33-4	Bus11-8	0.013	0.242	0.242	0.044	0.789	0.790	226.1%
Bus11-8	Bus11-9	0.036	0.023	0.043	0.086	0.073	0.113	164.1%
Bus33-1	Bus33-4	0.001	-0.054	0.054	0.006	-0.05	0.050	-6.8%
Bus33-1	Bus33-3	0.003	-0.053	0.053	0.011	-0.047	0.048	-9.1%
Bus33-3	Bus11-4	0.013	0.234	0.234	0.043	0.786	0.787	235.9%
Bus11-3	Bus11-2	0.038	0.024	0.045	0.039	0.024	0.046	1.9%
Bus11-4	Bus11-8	0.001	-0.013	0.013	0	-0.012	0.012	-8.0%
Bus33-3	Bus33-4	0.001	-0.054	0.054	0.001	-0.053	0.053	-1.9%
Bus33-2	Bus33-4	0.005	-0.052	0.052	0.009	-0.049	0.050	-4.6%
Bus11-5	Bus11-7	0.002	-0.012	0.012	0.002	-0.01	0.010	-16.2%
Bus11-9	Bus11-7	0.008	-0.006	0.010	0	-0.012	0.012	20.0%
Bus11-4	Bus11-7	0.019	0.005	0.020	0.09	0.077	0.118	502.9%
Bus11-7	Bus11-6	0.053	0.04	0.066	0.005	-0.007	0.009	-87.0%
Bus11-5	Bus11-6	0.037	0.023	0.044	0.013	0.001	0.013	-70.1%
Total Losses		0.403	1.369	1.427	0.528	2.68	2.732	91.4%

Table 3.21 Impact of DG Outage on Power Losses

The failure of a DG at Bus11-6 causes the increase of the power losses on particular lines but it decreases the power losses of other lines on the network. As seen in table 3.21, the power losses of the line between Bus11-4 and Bus11-7 increases by 502.9%, while the power losses of the line between Bus11-8 and Bus11-9 increases by 164.1% from the initial level. The increase of power losses on those lines is caused by additional power from the lines above Bus11-4 and Bus11-8. The additional power is needed to replace the power which is previously supplied by the failed DG at Bus11-6. As the power flow increased, the power losses will increase as well.

Contrary, the DG failure at Bus11-6 will reduce the supply to the demand connected at Bus11-5 and Bus11-7. As the result, the power which flows through the line between Bus11-6 and Bus11-5, and through the line between Bus11-6 and Bus11-7 will decrease by 70.1% and 87%, respectively. As the power flow decreased, so does the power losses.

From Busbar	To Busbar	Power Losses						
		DG Outage			On-site Generation			
		(MW)	(MVAr)	(MVA)	(MW)	(MVAr)	(MVA)	dSlosses
GSP	Bus33-1	0.003	0.069	0.069	0.003	0.053	0.053	-23.1%
GSP	Bus33-1	0.003	0.069	0.069	0.003	0.053	0.053	-23.1%
Bus33-2	Bus33-1	0	-0.054	0.054	0.001	-0.054	0.054	0.0%
Bus33-2	Bus11-1	0.028	0.505	0.506	0.028	0.504	0.505	-0.2%
Bus11-1	Bus11-2	0.046	0.032	0.056	0.046	0.031	0.055	-1.0%
Bus11-1	Bus11-3	0.001	-0.013	0.013	0.001	-0.013	0.013	0.0%
Bus11-3	Bus04-1	0.098	0.562	0.570	0.098	0.56	0.569	-0.3%
Bus33-4	Bus11-8	0.044	0.789	0.790	0.037	0.676	0.677	-14.3%
Bus11-8	Bus11-9	0.086	0.073	0.113	0.074	0.061	0.096	-15.0%
Bus33-1	Bus33-4	0.006	-0.05	0.050	0.005	-0.051	0.051	1.8%
Bus33-1	Bus33-3	0.011	-0.047	0.048	0.01	-0.048	0.049	1.6%
Bus33-3	Bus11-4	0.043	0.786	0.787	0.037	0.673	0.674	-14.4%
Bus11-3	Bus11-2	0.039	0.024	0.046	0.039	0.024	0.046	0.0%
Bus11-4	Bus11-8	0	-0.012	0.012	0	-0.013	0.013	8.3%
Bus33-3	Bus33-4	0.001	-0.053	0.053	0.001	-0.053	0.053	0.0%
Bus33-2	Bus33-4	0.009	-0.049	0.050	0.008	-0.049	0.050	-0.3%
Bus11-5	Bus11-7	0.002	-0.01	0.010	0.002	-0.01	0.010	0.0%
Bus11-9	Bus11-7	0	-0.012	0.012	0	-0.012	0.012	0.0%
Bus11-4	Bus11-7	0.09	0.077	0.118	0.077	0.063	0.099	-16.0%
Bus11-7	Bus11-6	0.005	-0.007	0.009	0.005	-0.007	0.009	0.0%
Bus11-5	Bus11-6	0.013	0.001	0.013	0.012	0	0.012	-8.0%
Total Losses		0.528	2.68	2.732	0.487	2.388	2.437	-10.8%

Table 3.22 Impact of Running On-site Generation on Power Losses

Table 3.22 shows that running on-site generation mechanism can reduce the power losses of the interconnected lines in the range of 8% and 16%, compared to the level of power losses at the event of DG outage.

DG outage at Bus11-6 causes scarcity of supply on the network. Therefore, by running onsite-generations, the energy generated from those generations can be used to replace the energy lost from the failed DG. Since the energy generated from the on-site generations can be directly used by the nearby demand, this will reduce the power drew from the network. As the power reduced, the power losses will decrease.

3.3 CHAPTER SUMMARY

This chapter describes the impact of DG connection and DSR implementation on an existing distribution network, in terms of voltage level, network capacity utilization and power losses of the network.

The impact of DG connection is examined by connecting a new DG to a generation-dominated busbar and a demand-dominated busbar. At a generation dominated-busbar, the impact of connecting of a new DG can be summarized as follow:

- DG connection at a generation-dominated busbar will increase the voltage level of the related busbars. Referring to the examples used in this research, the voltage level can increase up to 3.1% from the initial level. The highest increase of the voltage level occurs on the targeted busbar.
- The DG connection will also increase the network capacity utilization of the lines which are connected to the targeted busbar, due to the energy from the connected DG will be conveyed in the same direction with the initial power flow. As a result, it will increase the power flow on those lines. The analysis shows that the network capacity utilization of the lines will increase up to 42.5% from the initial level.
- As the power flow increased, the power losses will increase as well. In the examined case studies, the initial power losses increased up to 134.3%.

Meanwhile, at a demand-dominated busbar, a new DG connection might cause the followings:

- The connection of a new DG to a demand-dominated busbar will increase the voltage level of the related busbars. Based on the analysis for the case studies, this connection can increase the initial voltage level up to 2.8%. The highest increase of the voltage level occurs on the targeted busbar.
- At a demand-dominated busbar, the connection of a new DG might have different impacts, in terms of network capacity utilization. In one hand, this connection can reduce the network capacity utilization of some lines, but on the other hand, it will increase the network capacity utilization of other lines.

  The reduction of network capacity utilization due to the energy generated from the DG is used to supply the demand at the targeted busbar, so that, it will reduce the imported power from outside. Referring to the case studies, the reduction of the network capacity utilization can reach 47.2% from the initial level. Meanwhile, the increase of the network capacity utilization is caused by the energy from DG which is distributed in the same direction with the initial power flow to supply demand at particular busbars. The analysis shows that this will increase the initial power flow on those busbars up to 23.9%.

- The pattern of the power losses will follow the pattern of the power flow. If the power flow on a particular line decreased, the power losses on that line will also decrease, and vice versa. In the case studies, the connection of DG at a demand-dominated busbar will cause the initial power losses of some lines to decrease down to 76.8%. However, on some other lines, the DG connection will increase the power losses until 134% from the initial level.

For the purpose of examining the impact of DSR programme on the distribution network, the implementation of DSR is examined through three mechanisms, including demand reduction, demand shifting and running on-site generation.

- Demand reduction mechanism is applied following an outage on the network, i.e. when a particular line is out of service. Following the failure event, the initial voltage level of the busbar at one end of the line will increase by 0.1%, but at the other end, the initial voltage level will decrease by 1.4%. This failure causes the network capacity utilization of another line on the network to increase by 120.1%, which can lead to another failure. In addition, the initial power losses of this line increased by 238.5%.

  Through demand reduction mechanism, the voltage level of the related busbars increased by 1.1%, compared with the level at failure event. This mechanism will reduce the network capacity utilization and the power losses at the event of failure, down to 21.4% and 38.9%, respectively.

- Demand Shifting mechanism, which aims to shift the electricity consumption from peak times to of off-peak times, can reduce and flatten the electricity peak demand.

- On-site generations will be operated at the time of supply scarcity due to one DG is out of service. Following the outage, the initial voltage level of related busbars will decrease down to 5.1%. The largest voltage reduction occurs at the busbar where the DG previously connected. The DG outage will cause the power flow of the lines which are connected to the targeted busbar to increase up to 105.9%, while the initial power losses increased by five times.

- By running on-site generations, the voltage level at the event of failure will increase by 0.7%. This mechanism will cause the network capacity utilization of the exceeded line to decrease down to 97.0%, while the power losses at the event of failure can be reduced down to 16.9%.

4 EFFECTIVE DG INCENTIVE FOR DISTRIBUTION NETWORK OPERATORS

One of the purposes of connecting DGs to the distribution network is to increase the use of renewable energy sources to produce electricity, in order to reduce greenhouse gas emissions from electricity generation. It is expected that if more DGs connected to the network, more fossil-fuelled power plants will be replaced, eventually resulting less greenhouse gas emissions.

The existing mechanism, which incentivises a DNO merely based on the connected DG capacity (kW), seems to be a bit contrast with the purpose. The DNO will receive a higher incentive, if many more DGs can be connected to its network. Although the new connected DGs will only operate infrequently, the amount of incentive for the DNO will not be affected. In addition, the value of the incentives given to the DNOs is the same across the country, i.e. at £1/kW [54].

By considering that DG has many types of technology to generate energy, the current mechanism might give unfair treatment for every DG connection. The type of DG technology will determine the energy output from the connected DG. Different type of DG technology will have different value of DG parameters, including capacity factor, operational time and levelised cost of energy generation. As a result, the same DG capacity from different DG technologies will generate different amount of energy.

Another consideration that must be taken into account is the proposed location of DG connection because it will impact on the required investment cost to provide DG connection. Connecting DG in a remote area to the existing distribution network will require higher investment cost. The location of DG connection will also impact on the number of components that might be affected by that connection. The more the number of affected components, the higher the investment cost required.

Based on those two reasons, this research proposes a new approach in incentivising DNOs which is based on the utilization of available DG energy on the network and its relation with the requirement to upgrade the existing network, called energy-based DG incentive mechanism. The details of the principles, the structure and the methodology of the proposed mechanism, complemented with case studies are explained in the following sections.

4.1 IMPLEMENTATION OF ENERGY-BASED DG INCENTIVES

4.1.1 Principles of the Energy-based DG Incentives

Energy-based DG Incentive mechanism is developed to incentivise DNOs in facilitating DG connection on their distribution networks. The incentive is based on the utilization of available DG energy on the network, i.e. the actual amount of energy conveyed from the connected DG over the standard energy rated of the DG, and its relation with the requirement for network reinforcement. This mechanism considers two main parameters, i.e. the type of DG technology which will be connected to the network and the reinforcement cost needed to provide the connection.

4.1.2 Structure of the Incentive Mechanism

The structure of the proposed energy-based DG incentive adopted current DG incentive framework, which is established from a hybrid mechanism, i.e. giving DNOs a partial pass-through treatment and additional incentive rate to provide DG connection to their distribution network.

1). Level of Pass-through

As applied in current capacity-based DG incentive [54], energy-based DG incentive allows DNOs to pass 80% of their DG connection investment cost on to the customer who seeks for the connection.

2). Energy-based DG Incentive Rate

The energy-based DG incentive rate is developed from the remaining 20% of DG connection investment cost and is annuitized for a particular period of time. The period of time is assumed to be 15 years, as the assumed life time of DG connection assets.

3). Minimum and Maximum Thresholds of DG Incentive

The maximum threshold of the incentive will be given to the DNOs if the connected DG can convey energy at its standard energy rating. While the minimum threshold will be given if the connected DG convey the minimum required energy.

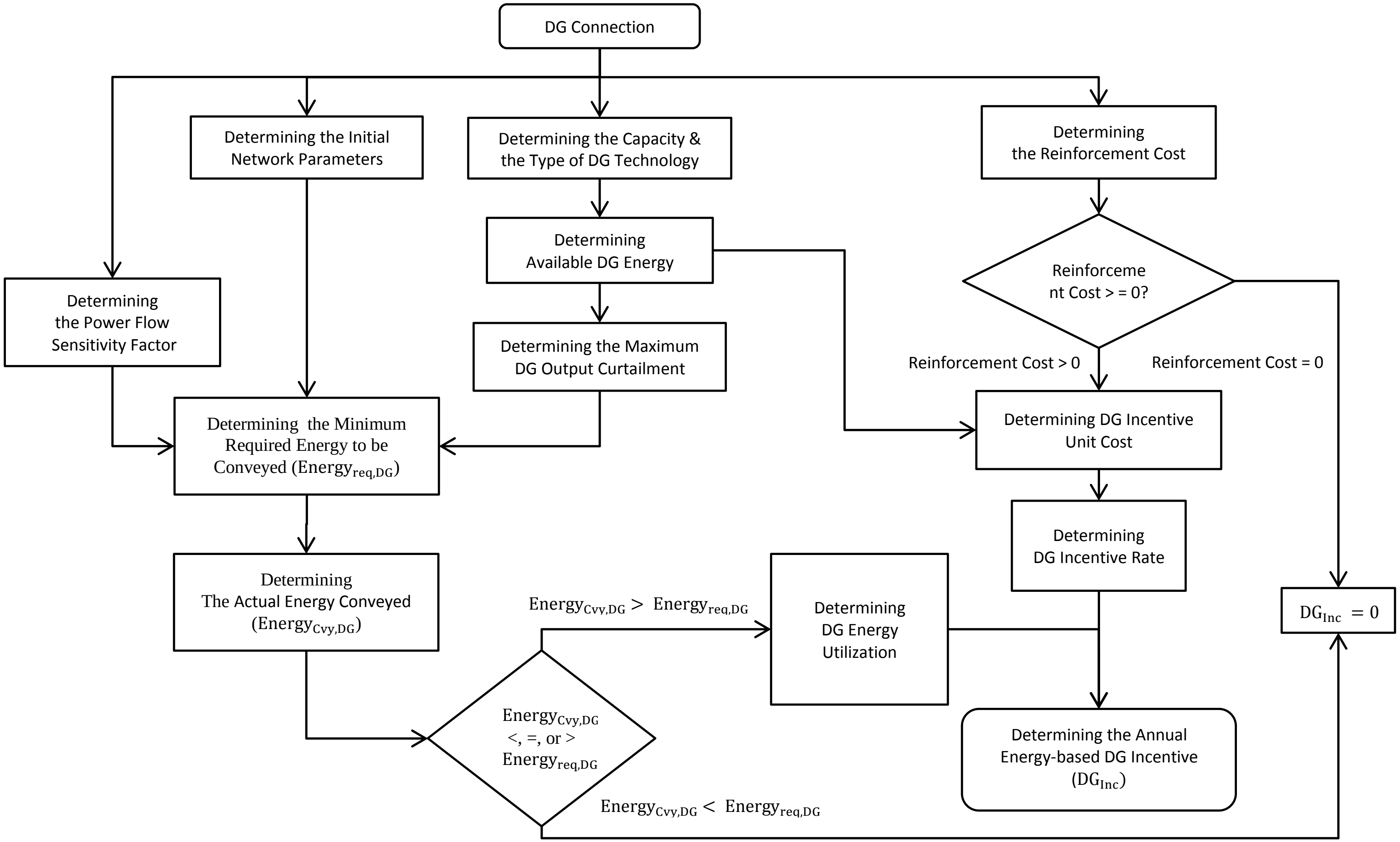

Figure 4.1 Flowchart for Energy-based DG Incentive Mechanism

4.1.3 Methodology to Develop Energy-based DG Incentive

The methodology used to develop energy-based DG incentive mechanism can be summarized by using the flowchart depicted in figure 4.1 (the details of the flowchart can be seen in appendix 2). The explanation of this methodology is as follows:

A. Determining the Reinforcement Cost

There are two main cost components in providing DG connection on distribution network, including the sole-use connection assets cost and the shared-use connection assets cost [77][78].

The sole-use connection assets are provided only for the customer who is seeking for DG connection. So that, the cost of these components will be directly passed on to the customers, while the shared-use connection assets will be used by all customers connected to the distribution network. Since the sole-use connection assets costs has been directly passed on to the customers, the reinforcement cost needed to provide DG connection is calculated based on the shared-use connection assets costs only.

In a case where the connection of a new DG does not require the network to be reinforced, which also means DNO do not need to spend any reinforcement costs, there will be no incentives given to the DNO.

B. Determining the Capacity and the Type of DG Technology

Different types of DG technology will have different value of DG parameters, including power factor ($\mathrm{DG_{p.pf}}$), capacity factor ($\mathrm{DG_{p.cf}}$), operational time ($\mathrm{DG_{p.oprtime}}$) and levelised cost of energy generation ($\mathrm{DG_{p.LCOEG}}$). These parameters will determine the maximum energy that can be generated from the DG ($\mathrm{DG_{p,EnergyMax}}$), as writen as:

$$\mathrm{DG_{p,EnergyMax}} = \mathrm{DG_{p,Cap}} * \mathrm{DG_{p,cf}} * \mathrm{DG_{p,cf}} * \mathrm{DG_{p,oprtime}} \qquad \ldots (4.1)$$

C. Determining the Maximum DG Output Curtailment

The maximum DG output curtailment represents the maximum energy that might be curtailed from the connected DG in order to suit the available capacity of the existing network. In terms of the variety of DG technologies, as previously explained, different DG technology will generate different amount of energy. Since the value of levelised cost of energy generation ($DG_{p.LCOEG}$) for each DG technology is different, the energy curtailment for each DG technology will be different as well, as written in equation (3.27) as:

$$DG_{p,EnergyCurtail} = \Delta DG_{p.m} x DG_{p.cf} x DG_{p.oprtime}$$

Where, $DG_{p,EnergyCurtail}$ represents the energy curtailment of the DG with the unit expressed in MWh and $\Delta DG_{p.m}$ represents the capacity curtailment of the DG with the unit expressed in MW. Then, the DG energy curtailment cost ($DG_{p,CurtailCost}$) can be calculated by using equation (3.29), as:

$$DG_{p,CurtailCost} = \Delta DG_{p.m} x DG_{p.cf} x DG_{p.oprtime} x DG_{p.LCOEG}; \text{ and}$$

$$\Delta DG_{p,m} = \frac{DG_{p,CurtailCost}}{DG_{p,cf} x DG_{p,oprtime} x DG_{p,LCOEG}}$$

In a case where network reinforcement mechanism is chosen to provide DG connection, the required reinforcement cost must have a value that corresponds to the cost of DG energy curtailment ($DG_{p,CurtailCost}$), or it is assumed that the DG energy curtailment is equal to the reinforcement cost ($InvCost_m$). So that, in order to calculate the maximum DG output curtailment ($\Delta DGmax_{p,m}$), the equation (3.32) can be applied as:

$$\Delta DGmax_{p,m} = \frac{InvCost_m}{DG_{p,cf} x DG_{p,oprtime} x DG_{p,LCOEG}}$$

D. Determining Power Flow Sensitivity Factor ($\frac{dP_{ik}}{dDG_{p.m}}$)

Power Flow Sensitivity Factor represents the sensitivity factor for the change in real power injection of DG_p at node m with the change in power flow from node i to node k can be obtained from equation (3.26) as:

$$\frac{dP_{ik}}{dDG_{p.m}} = \left(\frac{\partial|V_i|}{\partial P_p}\right)\frac{\partial P_m}{\partial|V_i|} + \left(\frac{\partial|V_k|}{\partial P_p}\right)\frac{\partial P_m}{\partial|V_k|} + \left(\frac{\partial\delta_i}{\partial P_p}\right)\frac{\partial P_m}{\partial\delta_i} + \left(\frac{\partial\delta_k}{\partial P_p}\right)\frac{\partial P_m}{\partial\delta_k}$$

$$+ j\left(\left(\frac{\partial|V_i|}{\partial Q_p}\right)\frac{\partial P_m}{\partial|V_i|} + \left(\frac{\partial|V_k|}{\partial Q_p}\right)\frac{\partial P_m}{\partial|V_k|} + \left(\frac{\partial\delta_i}{\partial Q_p}\right)\frac{\partial P_m}{\partial\delta_i} + \left(\frac{\partial\delta_k}{\partial P_p}\right)\frac{\partial P_m}{\partial\delta_k}\right)$$

Where the terms of $\frac{\partial P_m}{\partial|V_i|}$, $\frac{\partial P_m}{\partial|V_k|}$, $\frac{\partial P_m}{\partial\delta_i}$ and $\frac{\partial P_m}{\partial k}$ are obtained from equations (3.19) until (3.22) as:

$$\frac{\partial P_m}{\partial |V_i|} = 2|V_i^0|G_m - |V_k^0|G_m\cos(\delta_i^0 - \delta_k^0) - |V_k^0|B_m\sin(\delta_i^0 - \delta_k^0)$$

$$\frac{\partial P_m}{\partial |V_k|} = -|V_i^0|G_m\cos(\delta_i^0 - \delta_k^0) - |V_i^0|B_m\sin(\delta_i^0 - \delta_k^0)$$

$$\frac{\partial P_m}{\partial \delta_i} = |V_i^0||V_k^0|G_m\sin(\delta_i^0 - \delta_k^0) - |V_i^0||V_k^0|B_m\cos(\delta_i^0 - \delta_k^0)$$

$$\frac{\partial P_m}{\partial \delta_k} = -|V_i^0||V_k^0|G_m\sin(\delta_i^0 - \delta_k^0) + |V_i^0||V_k^0|B_m\cos(\delta_i^0 - \delta_k^0)$$

Meanwhile, the terms of $\frac{\partial |V_i|}{\partial P_p}$, $\frac{\partial |V_k|}{\partial P_p}$, $\frac{\partial \delta_i}{\partial P_p}$ and $\frac{\partial \delta_k}{\partial P_p}$ are the elements of JB3 and JB1, and $\frac{\partial |V_i|}{\partial Q_p}$, $\frac{\partial |V_k|}{\partial Q_p}$, $\frac{\partial \delta_i}{\partial Q_p}$ and $\frac{\partial \delta_k}{\partial Q_p}$ are the elements of JB4 and JB2, which can be obtained from equation (3.2) as:

$$\begin{bmatrix} \Delta\delta \\ \Delta|V| \end{bmatrix} = \begin{bmatrix} JB_1 & JB_2 \\ JB_3 & JB_4 \end{bmatrix} \begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix}$$

E. Determining the Initial Network Parameters

The initial network parameters, including the thermal rating ($S_{i,k}^{lim}$), the initial apparent power ($S_{i,k}$) and the initial power losses ($S_{Loss-i,k}$) of the line, are taken into account for the purpose of calculating the minimum required energy to be conveyed.

F. Determining the Minimum Required Energy to Be Conveyed ($DG_{p,EnMin}$)

The required energy to be conveyed is obtained from the summation of the maximum DG energy curtailment and the available network capacity prior to DG connection, as written in equation (3.37) as:

$$DG_{p,EnergyReq} =$$

$$(\Delta DGmax_{p,m} + \left(\frac{dP_{i,k}}{dDG_{p.m}}\right) * (S_{i,k}^{lim} - S_{i,k} + S_{Loss-i,k}) * DG_{p,pf}) * DG_{p,cf} * DG_{p,oprtime}$$

The terms of $\left(\frac{dP_{i,k}}{dDG_{p.m}}\right) * (S_{i,k}^{lim} - S_{i,k} + S_{Loss-i,k})$ represents the available network capacity prior to DG connection, expressed in MVA. Since the unit of $\Delta DGmax_{p,m}$ is expressed in MW, the value of network's available capacity must be multiplied by the power factor of the DG ($DG_{p,pf}$).

Then, the result of the capacity summation is multiplied by the capacity factor and the operational time of the connected DG, to obtain the minimum required energy to be conveyed by the DG.

G. Determining the DG Energy Utilization (DG_{EU})

DG energy utilisation (DG_{EU}) is described as the level of energy use from the maximum energy that can be generated from a particular DG. The unit of DG_{EU} is expressed in %, which can be calculated using the following equation:

$$DG_{EU} = \frac{(DG_{p,EnergyMax} - DG_{p,EnergyCurtail})}{DG_{p,EnergyMax}} \quad \text{... (4.2)}$$

Where, DG_{EU} represents the DG energy utilisation, $DG_{p,EnergyMax}$ represents the maximum energy generated by DG and $DG_{p,EnCurtail}$ represents the amount of energy curtailment of the DG. Since the subtraction of maximum energy generated by energy curtailed is equal to energy conveyed, $DG_{p,EnergyCvy}$, equation (4.2) can be written as [79]:

$$DG_{EU} = \frac{DG_{p,EnergyCvy}}{DG_{p,EnergyMax}} \quad \text{... (4.3)}$$

H. Determining the DG Incentive Unit Cost (DG_{UC})

The unit cost (DG_{UC}) of the energy-based DG incentive rate is derived from the reinforcement cost divided by the maximum energy that can be generated by DG [79]. This can be written as:

$$DG_{UC} = \frac{InvCost_m}{DG_{p,EnergyMax}} \quad \text{... (4.4)}$$

I. Determining the DG Incentive Rate (DG_{IR})

DG Incentive Rate (DG_{IR}) is determined based on the DG Incentive Unit Cost (DG_{UC}) which is annuitized for a particular period of time. The lifetime of the network component is assumed to be the period of time used for DG incentive rate calculation. Moreover, the value of DG incentive rate is calculated based on the 20% of the required reinforcement cost to provide DG connection. This due to 80% of the cost has been passed through to the customers who seek for DG connection.

As applied in the current DG incentive rate, there are two rate of return that will be considered to determine the annuitized unit cost or the DG incentive rate, i.e. the WACC and the additional rate of return. Current DG incentive rate used WACC of 5.6% and another 1% additional rate of return. Hence, the annuitized unit cost can be written as [79]:

$$\mathrm{DG_{IR}} = \frac{\mathrm{DG_{UC}} * (1+0.066-0.8) * \mathrm{WACC}}{(1-(1+\mathrm{WACC}))^{-\mathrm{nper}}} \quad \text{... (4.5)}$$

Where WACC represents the weighted average cost of capital of the investment and nper represent the lifetime of network component.

J. Determining Annual DG Incentive

Based on annuitized unit cost that has been calculated in (4.4), the energy-based DG incentive for distribution network operator ($\mathrm{DG_{Inc}}$), with the unit expressed in (£), can be calculated as follows:

$$\mathrm{DG_{Inc}} = \mathrm{DG_{IR}} * \mathrm{DG_{EU}} * \mathrm{DG_{p,EnergyCvy}} \quad \text{... (4.6)}$$

The above equation states that the amount of DG incentive that will be received by the DNO will be based on the amount of energy conveyed through the network.

K. Determining the Minimum Threshold of the Incentive

The minimum threshold of energy-based DG incentive is calculated based on the minimum requirement of energy must be conveyed through the network ($\mathrm{DG_{p,EnergyReq}}$).

By substituting the value of energy conveyed through the network, $\mathrm{DG_{p,EnergyCvy}}$ in equation (4.2) with the value of minimum required energy to be conveyed,$\mathrm{DG_{p,EnergyReq}}$, the minimum DG energy utilisation ($\mathrm{DG_{EUMin}}$) can be written as

$$\mathrm{DG_{EUMin}} = \frac{\mathrm{DG_{p,EnergyReq}}}{\mathrm{DG_{p,EnergyMax}}} \quad \text{... (4.7)}$$

Hence, the minimum annual DG incentive can be calculated as

$$\mathrm{DG_{IncMin}} = \mathrm{DG_{IR}} * \mathrm{DG_{EUMin}} * \mathrm{Energy_{req,DG}} \quad \text{... (4.8)}$$

L. Determining the Maximum Threshold of the Incentive

The maximum value of DG incentive is set based on the rated energy of the new connected DG on the network. In other words, maximum DG incentive will be given if the new DG is fully utilised, i.e. at the point where DG energy utilization, $\mathrm{DG_{EU}}$, is equal to 100%. Hence, the maximum annual DG incentive can be calculated as

$$DG_{IncMax} = DG_{IR} \ * \ DG_{EUMax} * DG_{p,EnergyMax}$$

$$DG_{IncMax} = DG_{IR} \ * \ 100\% * Energy_{rated,DG} \qquad \text{... (4.9)}$$

4.2 CASE STUDIES

4.2.1 Network Configuration

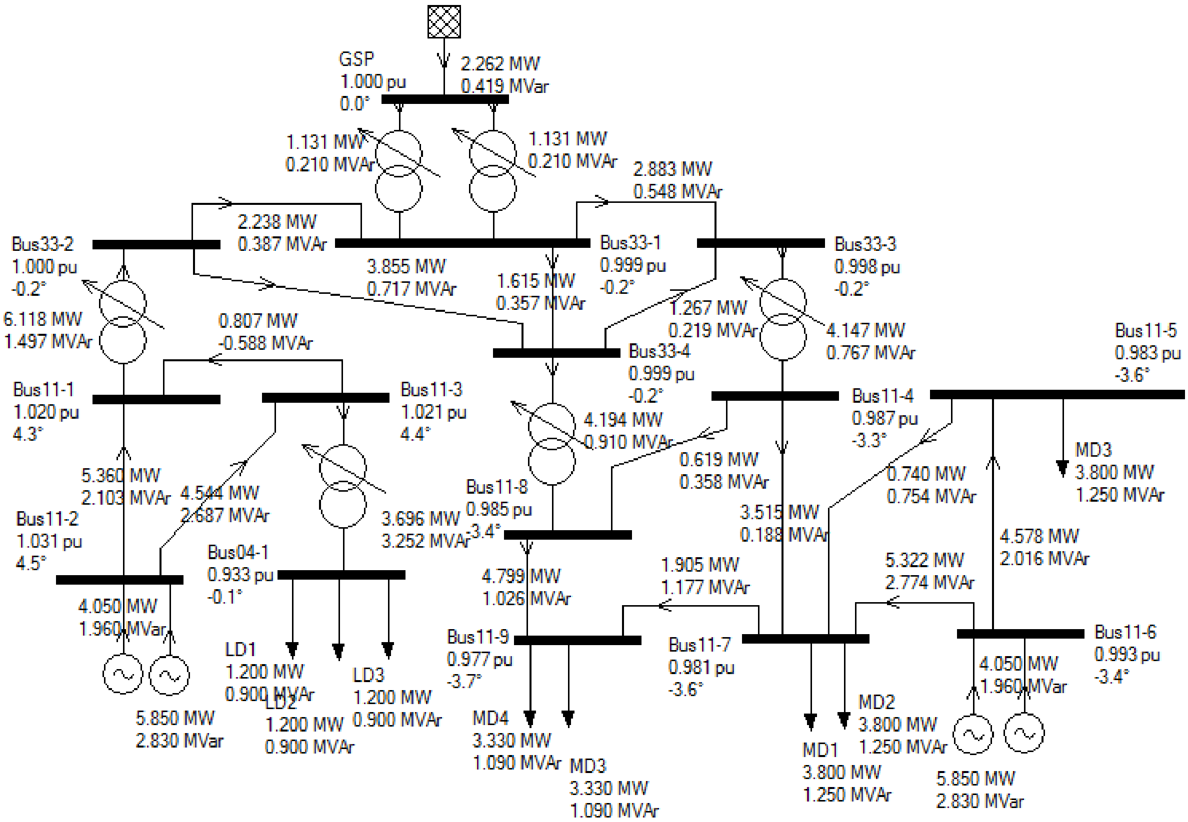

Figure 4.2 The Initial Network Power Flow

The initial network configuration and its power flow are depicted in figure 4.2. There are two generators which are already connected to Bus11-6, i.e. DG3 and DG4. Both DGs are hydro generations with the capacity of 6.5MVA for DG3 and of 4.5MVA for DG4. Then, a new DG will be connected to Bus11-6. The new DG is assumed to be an onshore wind generation with a capacity of 4.5MVA.

Figure 4.3 shows the impact of a new DG connection at Bus11-6. This connection causes the standard capacity of the line between Bus11-6 and Bus11-7 is exceeded. As shown, the power flowing through this line is 8.998MVA, which is exceeding the line's standard capacity of 7.049MVA.

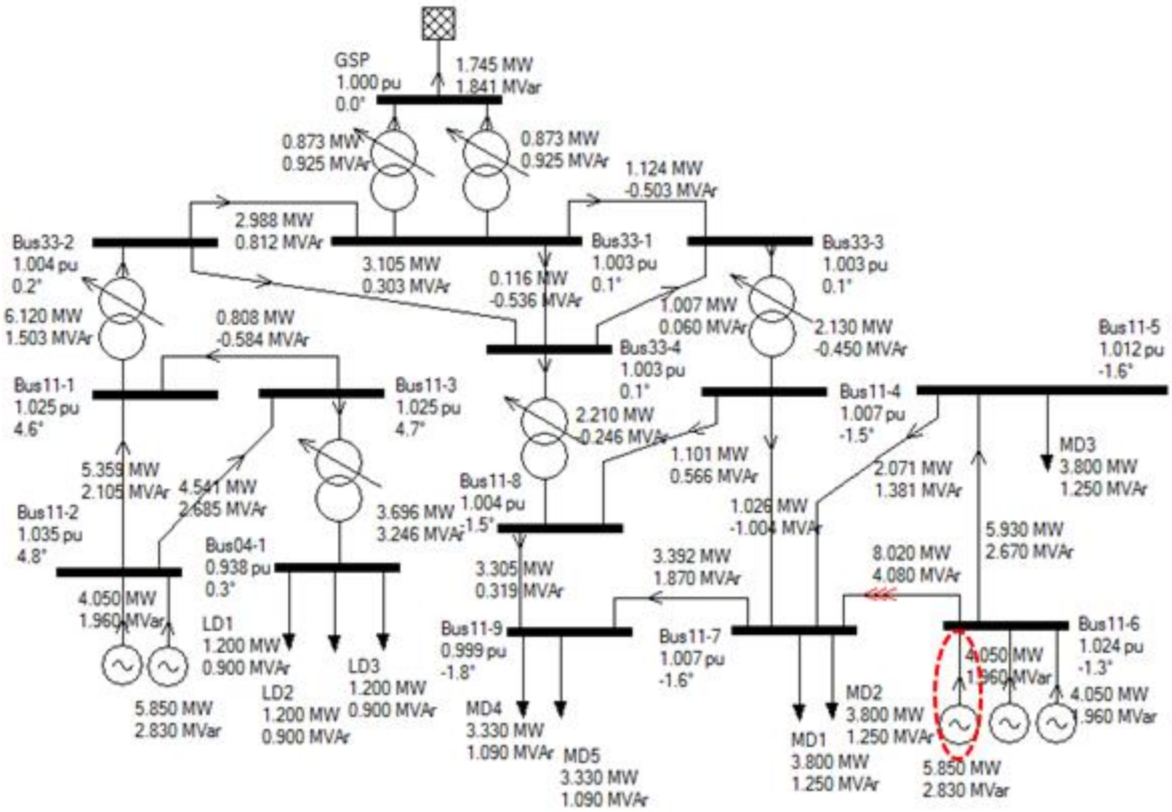

Figure 4.3 The Network Power Flow after DG Connection at Bus11-6

This condition requires the DNO to take one of the two possible mechanisms, either by curtailing the energy from connected DG or by reinforcing the network. Each mechanism is explained in the following sections.

4.2.2 DG Curtailment Mechanism

The first option to deal with the above problem is by curtailing the capacity of connected DGs at Bus11-6. The mechanism chosen for DG curtailment is by curtailing the capacity of the last connected DG to the system, known as Last in First out (LIFO) mechanism [26]. This mechanism is adopted because the energy conveyed from the DGs which are already connected to the network should not be affected by the new connection that comes later.

The connection of a new DG will impact on the value of the change in real power on the line between node-i to node-k ($\Delta P_{i,k}$), which can be derived from equation (3.25) as:

$$\Delta P_{i,k} = \sqrt{\left(\propto S_{i,k}^{lim}\right)^2 - \left(''Q_{i,k}\right)^2} - \sqrt{\left('S_{i,k}\right)^2 - \left('Q_{i,k}\right)^2} + \sqrt{\left(P_{Loss-i,k}\right)^2 + \left(Q_{Loss-i,k}\right)^2}$$

Assuming the following values of: $\propto$ = 100%, $S_{i.k}^{lim}$ = 7.049MVA, $''Q_{i.k}$= 3.214MVAr, $'S_{i.k}$= 6.002MVAr and $'Q_{i.k}$= 2.774MVAr, $P_{Loss-i.k}$ = 0.053MW and $Q_{Loss-i.k}$ = 0.040MVAr, the value of $\Delta P_{i.k}$ can be calculated and is equal to 0.995MW.

The sensitivity factor that relates the change in nodal real power injection at node m with the change in power flowing from node i to node k ($\frac{dP_{ik}}{dDG_{p.m}}$) can be calculated by using equation (3.26):

$$\frac{dP_{ik}}{dDG_{p.m}} = \left(\frac{\partial|V_i|}{\partial P_p}\right)\frac{\partial P_m}{\partial|V_i|} + \left(\frac{\partial|V_k|}{\partial P_p}\right)\frac{\partial P_m}{\partial|V_k|} + \left(\frac{\partial \delta_i}{\partial P_p}\right)\frac{\partial P_m}{\partial \delta_i} + \left(\frac{\partial \delta_k}{\partial P_p}\right)\frac{\partial P_m}{\partial \delta_k}$$

$$+ j\left(\left(\frac{\partial|V_i|}{\partial Q_p}\right)\frac{\partial P_m}{\partial|V_i|} + \left(\frac{\partial|V_k|}{\partial Q_p}\right)\frac{\partial P_m}{\partial|V_k|} + \left(\frac{\partial \delta_i}{\partial Q_p}\right)\frac{\partial P_m}{\partial \delta_i} + \left(\frac{\partial \delta_k}{\partial P_p}\right)\frac{\partial P_m}{\partial \delta_k}\right)$$

The above equation can be solved using MATLAB programme. For this particular example, the value of the sensitivity factor that relates the change in nodal real power injection at Bus11-6 with the change in power flowing from Bus11-6 to Bus11-7 is 0.3566.

Considering the value of $\Delta P_{i.k}$ =0.995 and the value of $\frac{dP_{ik}}{dDG_{p.m}}$ = 0.3566, the amount of DG output that must be curtailed to release the congestion ($\Delta DG_{p.m}$), can be obtained by using equation (3.23), as:

$$\Delta DG_{p.m} = \frac{\Delta P_{i,k}}{\left(\frac{dP_{i,k}}{dDG_{p.m}}\right)} = 2.79\text{MW}$$

By applying Last in First Out mechanism, the DG curtailment of 2.79MW will be applied to the new connected DG only. Since the new DG is a 4.5MVA wind generation with power factor of 0.9, it has rating capacity of 4.05MW and 1.96MVAr. By curtailing the output capacity with 2.79MW, it means that the remaining connected capacity is equal to 1.26MW and 0.610MVAr. The power flow analysis result after DG curtailment, to match the standard capacity of the line, is shown in figure 4.4.

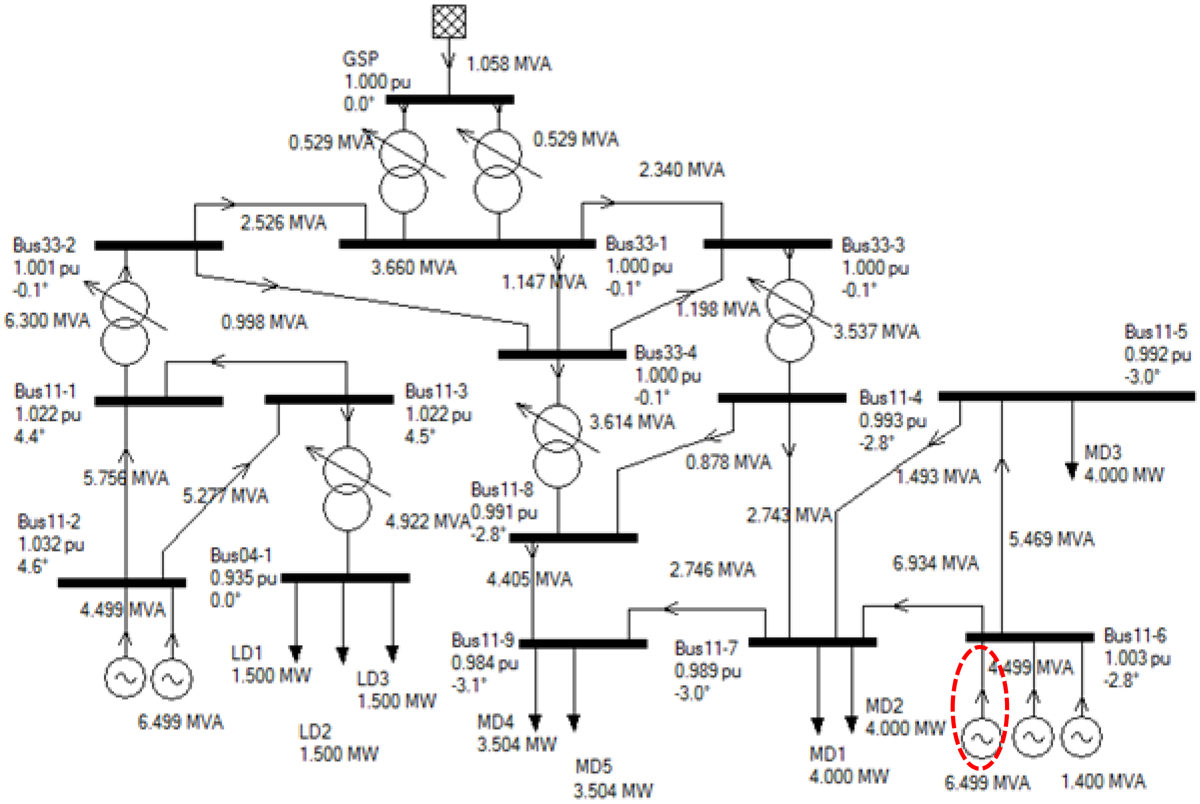

Figure 4.4 Network Power Flow after DG Curtailment at Bus11-6

Figure 4.4 shows the impact of DG curtailment mechanism which is applied on the new connected DG on Bus11-6. By curtailing 2.79MW of the connected DG, the power flows on the line between Bus11-6 and Bus11-7 decreases from 8.998MVA to 6.934MVA.

4.2.3 Network Reinforcement

In order to accommodate all connected DG capacity at Bus11-6, the line between Bus11-6 and Bus11-7 needs to be reinforced. Assuming that the standard line capacity will upgraded from 7.049MVA to 10.288MVA. The cost components of this reinforcement are presented in table 4.1 and are based on statement of methodology and charges for connection [77][78] .

COMPONENTS	Costs
Sole-Use Connection Assets	
Feasibility Studies	£2,080.00
Assessment and Design for all relevant work	£1,893.00
Assessment and Design of the Non-Contestable Work	£1,320.00
Design Approval of the Contestable Work	£553.00
Final Works and Phased Energisation	£1,342.00
Inspection and Monitoring - HV Network Site Visit	£3,168.00
Land Rights	£1,880.00
Contestable Work	
Installation of a 500m HV cable	£41,500.00
HV circuit Breaker at customer substation with suitable protection	£30,000.00
Actuators and Remote Control (RTU)	£16,000.00
Sub Total	**£99,736.00**
Shared-Use Connection Assets	
Non-Contestable Work	
2 HV Circuit Breakers at Primary substation @51,800.00	£103,600.00
Re-conductor of a 3000m HV overhead line	£80,000.00
Sub Total	**£183,600.00**

Table 4.1 Network Reinforcement Cost Components.

As described in chapter 2, the cost components considered in the calculation process to determine DG incentive only include the shared-use connection assets costs. So, in this particular example, the network reinforcement cost is £183,600.00.

The impact of network reinforcement is depicted in figure 4.5. The figure shows that after the line between Bus11-6 and Bus11-7 is upgraded, all connected DG capacity at Bus11-6 can be accommodate. A total of 9.818MVA apparent power can be conveyed through the reinforced line.

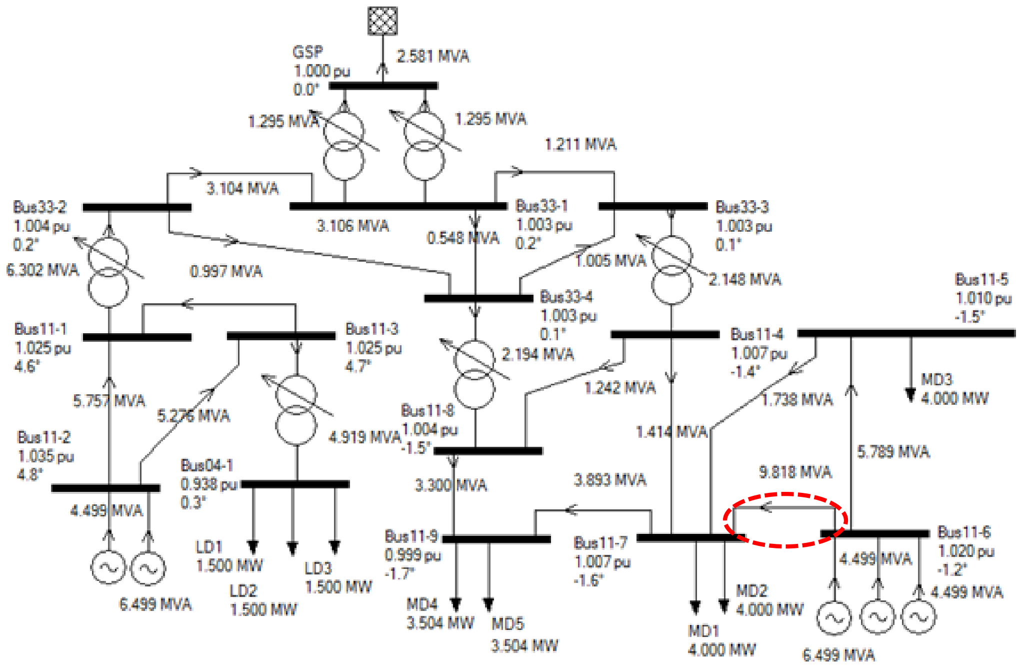

Figure 4.5 Network Power Flow after Network Reinforcement at Bus11-6

4.2.4 Impact of DG Curtailment and Network Reinforcement on Network Performance

The impact of both DG Curtailment and Network Reinforcement on the performance of the distribution network, including voltage level, network capacity utilization and network losses, are presented in table 4.2, table 4.3 and table 4.4, respectively.

1) Impact of DG Curtailment and Network Reinforcement on Voltage Level

Bus Name	**DG Connection at Bus11-6**		**After DG Curtailment**			**After Network Reinforcement**		
	Voltage Mag (pu)	**Voltage Angle (deg)**	**Voltage Mag (pu)**	**Voltage Angle (deg)**	**dV**	**Voltage Mag (pu)**	**Voltage Angle (deg)**	**dV**
GSP	1		1		0.0%	1		0.0%
Bus33-1	1.003	0.15	1	-0.09	-0.3%	1.003	0.15	0.0%
Bus33-2	1.004	0.17	1.001	-0.07	-0.3%	1.004	0.17	0.0%
Bus11-1	1.025	4.57	1.022	4.35	-0.3%	1.025	4.57	0.0%
Bus11-2	1.035	4.82	1.032	4.61	-0.3%	1.035	4.82	0.0%
Bus11-3	1.025	4.68	1.022	4.46	-0.3%	1.025	4.68	0.0%
Bus04-1	0.938	0.25	0.935	0.01	-0.3%	0.938	0.26	0.0%
Bus33-4	1.003	0.14	1	-0.1	-0.3%	1.003	0.14	0.0%
Bus11-8	1.004	-1.51	0.991	-2.78	-1.3%	1.004	-1.49	0.0%
Bus11-9	0.999	-1.76	0.984	-3.08	-1.5%	0.999	-1.73	0.0%
Bus33-3	1.003	0.13	1	-0.11	-0.3%	1.003	0.13	0.0%
Bus11-4	1.007	-1.47	0.993	-2.75	-1.4%	1.007	-1.45	0.0%
Bus11-7	1.007	-1.64	0.989	-3	-1.8%	1.007	-1.61	0.0%
Bus11-5	1.012	-1.58	0.992	-2.98	-2.0%	1.01	-1.51	-0.2%
Bus11-6	1.024	-1.32	1.003	-2.75	-2.1%	1.02	-1.2	-0.4%

Table 4.2 Impact of DG Curtailment and Network Reinforcement on Voltage Level

As presented in table 4.2, both DG curtailment and network reinforcement mechanism can reduce the voltage level of some busbars on the network.

The reduction of voltage level due to DG curtailment mechanism is in the range between 1.8% and 2.1% from the initial level, while network reinforcement mechanism will reduce the voltage level by 0.2% until 0.4% from the initial level. The largest decrease occurs on the targeted busbar, where the DG is connected.

2) Impact of DG Curtailment and Network Reinforcement on Network Capacity Utilization

From Busbar	To Busbar	Power Rating (MVA)	Network Capacity Utilization					
			DG Connection at Bus11-6		After DG Curtailment		After Network Reinforcement	
GSP	Bus33-1	40.000	1.272	3.2%	529	1.3%	1.295	3.2%
GSP	Bus33-1	40.000	1.272	3.2%	529	1.3%	1.295	3.2%
Bus33-2	Bus33-1	15.433	3.094	20.0%	2.526	16.4%	3.104	20.1%
Bus33-2	Bus11-1	10.000	6.302	63.0%	6.300	63.0%	6.302	63.0%
Bus11-1	Bus11-2	7.049	5.757	81.7%	5.756	81.7%	5.757	81.7%
Bus11-1	Bus11-3	7.049	0.997	14.1%	998	14.2%	0.997	14.1%
Bus11-3	Bus04-1	7.500	4.919	65.6%	4.922	65.6%	4.919	65.6%
Bus33-4	Bus11-8	10.000	2.220	22.2%	3.614	36.1%	2.194	21.9%
Bus11-8	Bus11-9	7.049	3.321	47.1%	4.405	62.5%	3.300	46.8%
Bus33-1	Bus33-4	15.433	0.548	3.6%	1.147	7.4%	0.548	3.6%
Bus33-1	Bus33-3	15.433	1.231	8.0%	2.340	15.2%	1.211	7.8%
Bus33-3	Bus11-4	10.000	2.174	21.7%	3.537	35.4%	2.148	21.5%
Bus11-3	Bus11-2	7.049	5.276	74.8%	5.277	74.9%	5.231	74.2%
Bus11-4	Bus11-8	7.049	1.236	17.5%	878	12.5%	1.242	17.6%
Bus33-3	Bus33-4	15.433	1.009	6.5%	1.197	7.8%	1.005	6.5%
Bus33-2	Bus33-4	15.433	3.116	20.2%	3.660	23.7%	3.106	20.1%
Bus11-5	Bus11-7	7.049	2.487	35.3%	1.493	21.2%	1.738	24.7%
Bus11-9	Bus11-7	7.049	3.874	55.0%	2.746	39.0%	3.893	55.2%
Bus11-4	Bus11-7	7.049	1.435	20.4%	2.743	38.9%	1.414	20.1%
Bus11-7	Bus11-6	7.049	8.998	127.6%	6.934	98.4%	9.818	98.2%
Bus11-5	Bus11-6	7.049	6.504	92.3%	5.469	77.6%	5.789	82.1%

Table 4.3 Impact of DG Curtailment and Network Reinforcement on Network Utilization

As previously explained, the connection of a new DG to a generation-dominated area/busbar might cause the standard capacity of particular network components are exceeded. DG curtailment mechanism aims to reduce the connected DG capacity to suit the standard capacity of network components. If the connected DG capacity is reduced, the utilization of network capacity will decrease.

As shown in table 4.3, the curtailment of connected DG at Bus11-6 will impact on reducing the network capacity utilization of the line between Bus11-6 and Bus11-5, from 92.3% down to 77.6%. This mechanism also reduces the network capacity of the line between Bus11-6 and Bus11-7, from 127.6% down to 98.4%.

Meanwhile, the aim of network reinforcement mechanism is to upgrade the capacity of network components, which in turn, it can accommodate all available DG capacity connected to the network. As a result, it can reduce the network capacity utilization of the line. For instance, by referring to the line between Bus 11-6 and Bus11-7, the power flow of 8.998MVA is equal to the utilization of 127.6% of the standard capacity of 7.049MVA. Then, by upgrading the network capacity to 10MVA, the power flow becomes 9.818MVA, or equal to 98.2% network capacity utilization. The same impact can also be investigated from the network capacity utilization of the line between Bus11-5 and Bus11-6, which decreases from 92.3% down to 82.1%.

2) Impact of DG Curtailment and Network Reinforcement on Power Losses

From Busbar	To Busbar	Power Losses						
		DG Connection at Bus11-6			After DG Curtailment			
		(MW)	(MVAr)	(MVA)	(MW)	(MVAr)	(MVA)	dSlosses
GSP	Bus33-1	0	0.005	0.005	0	0.001	0.001	-80.0%
GSP	Bus33-1	0	0.005	0.005	0	0.001	0.001	-80.0%
Bus33-2	Bus33-1	0.003	-0.053	0.053	0.002	-0.054	0.054	1.8%
Bus33-2	Bus11-1	0.027	0.495	0.496	0.027	0.497	0.498	0.4%
Bus11-1	Bus11-2	0.045	0.03	0.054	0.045	0.031	0.055	1.0%
Bus11-1	Bus11-3	0.001	-0.013	0.013	0.001	-0.013	0.013	0.0%
Bus11-3	Bus04-1	0.096	0.546	0.554	0.096	0.55	0.558	0.7%
Bus33-4	Bus11-8	0.004	0.064	0.064	0.009	0.171	0.171	167.0%
Bus11-8	Bus11-9	0.016	0.002	0.016	0.029	0.015	0.033	102.5%
Bus33-1	Bus33-4	0	-0.055	0.055	0	-0.055	0.055	0.0%
Bus33-1	Bus33-3	0	-0.055	0.055	0.002	-0.054	0.054	-1.8%
Bus33-3	Bus11-4	0.003	0.061	0.061	0.009	0.164	0.164	168.9%
Bus11-3	Bus11-2	0.038	0.023	0.044	0.038	0.023	0.044	0.0%
Bus11-4	Bus11-8	0.002	-0.012	0.012	0.001	-0.012	0.012	-1.0%
Bus33-3	Bus33-4	0	-0.055	0.055	0	-0.054	0.054	-1.8%
Bus33-2	Bus33-4	0.003	-0.053	0.053	0.004	-0.052	0.052	-1.8%
Bus11-5	Bus11-7	0.009	-0.005	0.010	0.003	-0.01	0.010	0.0%
Bus11-9	Bus11-7	0.022	0.008	0.023	0.011	-0.002	0.011	-52.2%
Bus11-4	Bus11-7	0.003	-0.011	0.011	0.011	-0.002	0.011	-1.9%
Bus11-7	Bus11-6	0.113	0.098	0.150	0.07	0.056	0.090	-40.1%
Bus11-5	Bus11-6	0.059	0.044	0.074	0.043	0.029	0.052	-29.5%
Total Losses		0.444	1.069	1.158	0.401	1.23	1.294	11.8%

Table 4.4 Impact of DG Curtailment on Power Losses

DG curtailment mechanism at Bus11-6 causes the reduction of the power losses on the lines which are connected to Bus11-6.

As seen in table 4.4, the power losses of the line between Bus11-6 and Bus11-7 decreased by 40.1%, while the power losses of the line between Bus11-6 and Bus11-5 decreases by 29.5%, compared with the power losses at the time after a new DG connection took place. The decrease of power losses is caused by the curtailment of power supply connected at Bus11-6.

This will reduce the power flow on the lines connected to this busbar. As the power flow decreased, the power losses will decrease as well.

From Busbar	To Busbar	Power Losses						
		DG Connection at Bus11-6			After Network Reinforcement			
		(MW)	(MVAr)	(MVA)	(MW)	(MVAr)	(MVA)	dSlosses
GSP	Bus33-1	0	0.005	0.005	0	0.005	0.005	0.0%
GSP	Bus33-1	0	0.005	0.005	0	0.005	0.005	0.0%
Bus33-2	Bus33-1	0.003	-0.053	0.053	0.003	-0.053	0.053	0.0%
Bus33-2	Bus11-1	0.027	0.495	0.496	0.027	0.495	0.496	0.0%
Bus11-1	Bus11-2	0.045	0.03	0.054	0.045	0.03	0.054	0.0%
Bus11-1	Bus11-3	0.001	-0.013	0.013	0.001	-0.013	0.013	0.0%
Bus11-3	Bus04-1	0.096	0.546	0.554	0.096	0.546	0.554	0.0%
Bus33-4	Bus11-8	0.004	0.064	0.064	0.003	0.062	0.062	-3.2%
Bus11-8	Bus11-9	0.016	0.002	0.016	0.016	0.002	0.016	0.0%
Bus33-1	Bus33-4	0	-0.055	0.055	0	-0.055	0.055	0.0%
Bus33-1	Bus33-3	0	-0.055	0.055	0	-0.055	0.055	0.0%
Bus33-3	Bus11-4	0.003	0.061	0.061	0.003	0.06	0.060	-1.6%
Bus11-3	Bus11-2	0.038	0.023	0.044	0.038	0.023	0.044	0.0%
Bus11-4	Bus11-8	0.002	-0.012	0.012	0.002	-0.012	0.012	0.0%
Bus33-3	Bus33-4	0	-0.055	0.055	0	-0.055	0.055	0.0%
Bus33-2	Bus33-4	0.003	-0.053	0.053	0.003	-0.053	0.053	0.0%
Bus11-5	Bus11-7	0.009	-0.005	0.010	0.004	-0.01	0.011	4.6%
Bus11-9	Bus11-7	0.022	0.008	0.023	0.022	0.008	0.023	0.0%
Bus11-4	Bus11-7	0.003	-0.011	0.011	0.003	-0.011	0.011	0.0%
Bus11-7	Bus11-6	0.113	0.098	0.150	0.074	0.107	0.130	-13.0%
Bus11-5	Bus11-6	0.059	0.044	0.074	0.047	0.033	0.057	-22.0%
Total Losses		0.444	1.069	1.158	0.387	1.059	1.127	-2.6%

Table 4.5 Impact of Network Reinforcement on Power Losses

Network reinforcement on the line between Bus11-6 and Bus11-7 will also reduce the power losses on the reinforced line due to capacity upgrading of the line. This can be seen on the reduction of the power losses by 13%, compared with the power losses before network reinforcement, as seen in table 4.5.

Furthermore, upgrading line’s capacity also means increasing the proportion of power flow through the reinforced line, which in turn, it will reduce the power flow proportion of another line interconnected with this line. As the power flow decreased, the power losses will also decrease. This can be seen from the decrease of power losses on the line between Bus11-6 and Bus11-5 by 22%, compared with the power losses before network reinforcement took place.

4.2.5 Incentive Thresholds

A. The Minimum Threshold of Energy-Based DG Incentive

As presented in table 4.1, the cost needed to reinforce the line between Bus11-6 and Bus11-7 is £183.600. In order to determine the minimum value of DG incentive, the values $\Delta \mathrm{Gmax}_{\mathrm{p,m}}$ (maximum DG curtailment) and $\mathrm{Energy}_{\mathrm{req,DG}}$ (minimum required energy to be conveyed) must be calculated first by using equation (3.32) and (3.37).

Considering the DG capacity factor ($\mathrm{DG}_{\mathrm{p,cf}}$) = 0.35, the DG operational time ($\mathrm{DG}_{\mathrm{p,oprtime}}$) = 8760 hours, and the levelised cost of energy generation ($\mathrm{DG}_{\mathrm{p,LCOEG}}$) = £75/MWh, the maximum DG curtailment ($\Delta \mathrm{DGmax}_{\mathrm{p,m}}$) can be calculated by using equation (3.32) as:

$$\Delta \mathrm{DGmax}_{\mathrm{p,m}} = \frac{\mathrm{InvCost}_{\mathrm{m}}}{\mathrm{DG}_{\mathrm{p,cf}} \mathrm{x} \mathrm{DG}_{\mathrm{p,oprtime}} \mathrm{x} \mathrm{DG}_{\mathrm{p,LCOEG}}} = 0.798\mathrm{MW}$$

Given the sensitivity factor $\left(\frac{\mathrm{dP}_{\mathrm{ik}}}{\mathrm{dDG}_{\mathrm{p.m}}}\right)$ for the line between Bus11-6 and Bus11-7 = 0.3566, the thermal capacity limit of the congetsed line ($\mathrm{S}_{\mathrm{i.k}}^{\mathrm{lim}}$) = 7.049MVA, the load flow prior to DG connection ($\mathrm{S}_{\mathrm{i.k}}$) = 6.002MVA and the initial power losses of the congested line ($\mathrm{S}_{\mathrm{Losses-i.k}}$) = 0.0664MVA, and the DG power factor ($\mathrm{DG}_{\mathrm{p,pf}}$) = 0.9, the required energy to be conveyed at this point can be obtained from equation (3.37) as:

$$\mathrm{DG}_{\mathrm{p,EnergyReq}} = (\Delta \mathrm{DGmax}_{\mathrm{p,m}} + \left(\frac{\mathrm{dP}_{\mathrm{ik}}}{\mathrm{dDG}_{\mathrm{p.m}}}\right) * (\mathrm{S}_{\mathrm{i.k}}^{\mathrm{lim}} - \mathrm{S}_{\mathrm{i.k}} + \mathrm{S}_{\mathrm{Losses-i.k}}) * \mathrm{DG}_{\mathrm{p,pf}}) * \mathrm{DG}_{\mathrm{p,cf}} * \mathrm{DG}_{\mathrm{p,oprtime}}$$

$$= 3{,}543\mathrm{MWh}$$

Hence, the minimum required energy to be conveyed by the new connected DG is 3,543MWh, as depicted in figure 4.6.

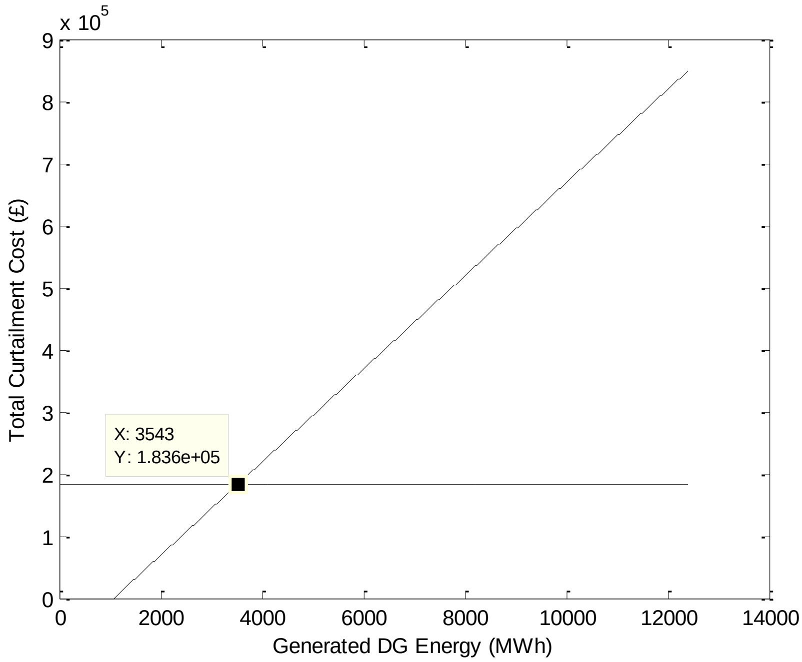

Figure 4.6 DG Curtailment Cost vs Network Reinforcement Cost

Given DG capacity ($\mathrm{DG_{p,Cap}}$) = 4.5MVA, the maximum energy that can be generated by DG in one year period is calculated using (4.6) as:

$$\mathrm{DG_{p,EnergyMax}} = \mathrm{DG_{p,Cap}} * \mathrm{DG_{p,pf}} * \mathrm{DG_{p,cf}} * \mathrm{DG_{p,oprtime}}$$

$$= 12{,}4179\mathrm{MWh}$$

By comparing the value of minimum required energy to be conveyed ($\mathrm{DG_{p,EnergyReq}}$) and the value of DG rated energy ($\mathrm{DG_{p,EnergyMax}}$), the minimum DG energy utilisation ($\mathrm{DG_{EUMin}}$) can be obtained from equation (4.7) as:

$$\mathrm{DG_{EUMin}} = \frac{\mathrm{DG_{p,EnergyReq}}}{\mathrm{DG_{p,EnergyMax}}} = 28.5\%$$

Then, the unit cost of DG incentive can be calculated using equation (4.3):

$$\mathrm{DG_{UC}} = \frac{\mathrm{InvCost_m}}{\mathrm{DG_{p,EnergyMax}}} = £14.79/\mathrm{MWh}$$

The DG incentive rate is calculated based on the value of WACC, which is assumed to be 5.6%, and additional rate of return, which is assumed to be 1%, and the lifetime of network component, which is assumed to be 15 years. By using equation (4.4), the DG incentive rate can be obtained from

$$\mathrm{DG_{IR}} = \frac{\mathrm{DG_{UC}} * (1+0.066-0.8) * \mathrm{WACC}}{(1-(1+\mathrm{WACC}))^{-\mathrm{nper}}} = £0.39/\mathrm{MWh}$$

Hence, the minimum annual DG incentive can be calculated using equation (4.8) as:

$$\mathrm{DG_{IncMin}} = \mathrm{DG_{IR}} * \mathrm{DG_{EUMin}} * \mathrm{Energy_{req}}$$

$$= £398.88$$

B. The Maximum Threshold of Energy-Based DG Incentive

The maximum threshold of the incentive will be given to the DNO if the connected DG can convey 100 % of its available energy during one year period, as written in (4.9) as:

$$\mathrm{DG_{IncMax}} = \mathrm{DG_{IR}} * 100\% * \mathrm{Energy_{rated,DG}}$$

$$= £4{,}898.00$$

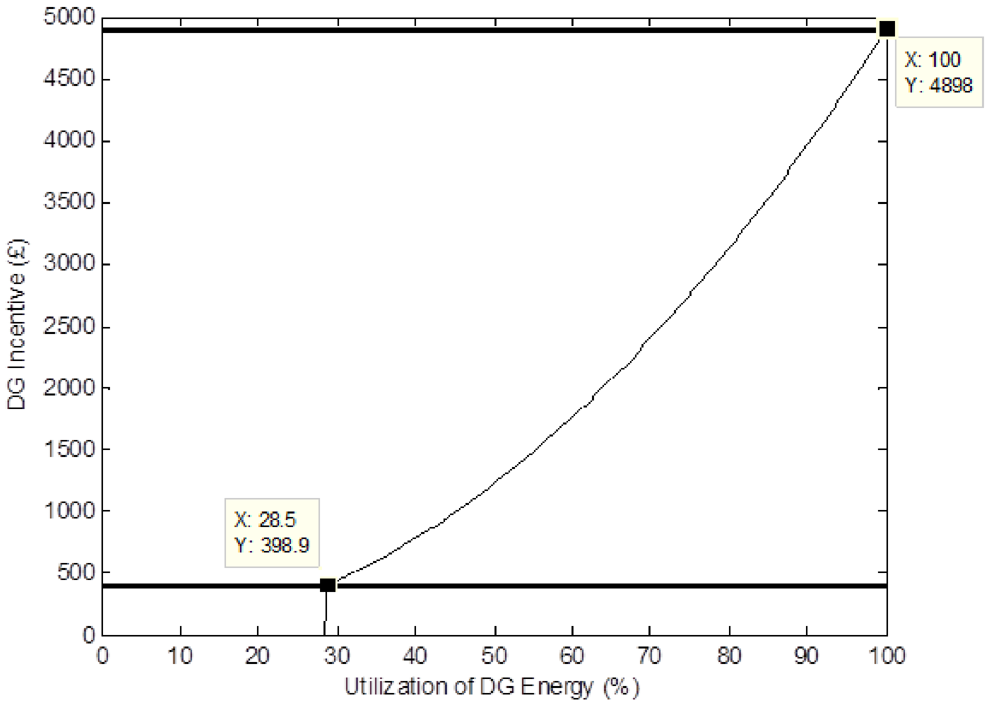

Figure 4.7 The Thresholds of Energy-based DG Incentive for Wind Generation

Figure 4.7 shows the graph of energy-based DG incentive for the DG connection at Bus11-6. The energy-based DG incentive for DNOs will increase exponentially in accordance with the increase of DG Energy Utilization.

The minimum threshold of the incentive of £398.88 will be given to the DNO if the connected DG, which is a 4.5MVA wind generation, can convey 28.54% of its available energy during one year period. If the connected DG cannot meet this minimum requirement, the incentive for DNO will be equal to 0.

Meanwhile, the maximum incentive of £4,898.00 will be given to the DNO if the connected DG can convey 100% of its rated output energy, which is equal to 12,4179MWh, in this particular example.

4.2.6 Assessment of Energy-based DG Incentive Mechanism Associated with DG Technology

This section describes the assessment of energy-based DG incentive mechanism related to the impact of the DG technology used to generate energy, the location of DG connection and the configuration of the network where the DG connected.

As described in chapter 2, every DG technology will come along with different parameter values including capacity factor, operational time and levelised cost of energy generation. The first two parameters will significantly impact on the calculation of the maximum energy can be generated from each DG technology, which in turn, it will impact on the calculation of the minimum required energy to be conveyed as well as the minimum annual energy-based DG incentive for the DNO.

A). Total Energy Yield per Year for Different DG Technology

By assuming that all DG technologies have the same capacity of 4.5MVA, power factor of 0.9 and operational time of 8760 hours/year, the maximum energy can be yielded in one year period for each DG technology can be calculated using equation (4.1) as:

$$\mathrm{DG_{p,EnergyMax}} = \mathrm{DG_{p,cap}} * \mathrm{DG_{p.pf}} * \mathrm{DG_{p.cf}} * \mathrm{DG_{p.oprtime}}$$

Technology	Capacity (MVA)	Power Factor	Capacity Factor	Real Power (MW)	Operational Time/year (hours)	Energy Yield /year (MWh)
Solar PV	4.5	0.9	0.097	0.393	8760	3,441.37
Onshore Wind	4.5	0.9	0.350	1.418	8760	12,417.30
Offshore Wind	4.5	0.9	0.430	1.742	8760	15,255.54
Hydro	4.5	0.9	0.400	1.620	8760	14,191.20
CCGT CHP	4.5	0.9	0.675	2.734	8760	23,947.65
Geothermal	4.5	0.9	0.800	3.240	8760	28,382.40
Biomass	4.5	0.9	0.900	3.645	8760	31,930.20

Table 4.6 Energy Yield per annum for Various DG Technologies

As presented in table 4.6, the maximum energy for one DG technology and another, in one year period, will be different although the DG capacity is the same for all DG technologies. Solar PV will generate the lowest energy of 3,441MWh because it has the lowest capacity factor of 0.097, while biomass, which has the highest capacity factor of 0.9, will generate the highest energy of 31,930MWh.

The comparison of the energy output from one DG technology and another is proportional to the ratio of their capacity factor. The higher the capacity factor of the DG, the higher the energy output.

B). Minimum Threshold of Energy-based DG Incentive

As described in previous section, the minimum threshold of energy based DG incentive is based on the minimum required energy to be conveyed by DG, which can be obtained by using equations (3.32) and (3.37) as written as:

$$\mathrm{DG}_{\mathrm{p,EnergyReq}} =$$

$$(\Delta\mathrm{DGmax}_{\mathrm{p,m}} + \left(\frac{\mathrm{dP}_{\mathrm{i,k}}}{\mathrm{dDG}_{\mathrm{p.m}}}\right) * (\mathrm{S}_{\mathrm{i,k}}^{\mathrm{lim}} - \mathrm{S}_{\mathrm{i,k}} + \mathrm{S}_{\mathrm{Loss-i,k}}) * \mathrm{DG}_{\mathrm{p,pf}}) * \mathrm{DG}_{\mathrm{p,cf}} {}^{*} \mathrm{DG}_{\mathrm{p,oprtime}}$$

Where

$$\Delta\mathrm{DGmax}_{\mathrm{p,m}} = \frac{\mathrm{InvCost}_{\mathrm{m}}}{\mathrm{DG}_{\mathrm{p,cf}}\mathrm{x}\mathrm{DG}_{\mathrm{p,oprtime}}\mathrm{x}\mathrm{DG}_{\mathrm{p,LCOEG}}}$$

From those equations, it can be seen that the parameters attached on each DG technology, including capacity factor, operational time and levelised cost of energy generation have significant impact in determining the minimum requirement for DG to convey energy through the network.

Technology	**cf**	**Cap**	**pf**	**Opr Time**	**LCOEG**	**Investment Cost**	**delta DGmax**	**Minimum Required Energy**
		(MVA)		**(hours)**	**(£/MWh)**	**(£)**	**(MW)**	**(MWh)**
Solar PV	0.097	4.5	0.9	8,760	202.00	183,600.00	1.07	1,212.55
Offshore wind	0.430	4.5	0.9	8,760	149.00	183,600.00	0.33	2,578.22
Onshore wind	0.350	4.5	0.9	8,760	75.00	183,600.00	0.80	3,543.59
Geothermal	0.800	4.5	0.9	8,760	132.00	183,600.00	0.20	3,895.11
Biomass	0.900	4.5	0.9	8,760	122.40	183,600.00	0.19	4,317.23
CHP	0.675	4.5	0.9	8,760	60.40	183,600.00	0.51	5,152.65
Hydro (run of river)	0.400	4.5	0.9	8,760	42.00	183,600.00	1.25	5,623.53
Hydro (reservoir)	0.400	4.5	0.9	8,760	42.00	183,600.00	1.25	5,623.53

Table 4.7 Energy Yield per annum for Various DG Technologies

Referring to table 4.7, if a DNO connected a 4.5MVA DG with Solar PV technology, they are required to convey energy as minimum as 1,213MWh per year, in order to receive energy-based DG incentive. Solar PV has the least energy requirement because it has the highest value of levelised costs of energy generation despite it has the lowest capacity factor.

Meanwhile, if the connected DG is a hydro technology, the DNO is required to convey 5,624MWh of energy. Hydro technologies (for both run of river and reservoir mechanisms) have the highest energy requirement because their levelised costs of energy generation and capacity factor are low.

Then, by using the same procedures as applied for wind generation connection, the other values, including the unit cost of the incentive ($\mathrm{DG_{UC}}$), the minimum DG energy utilization ($\mathrm{DG_{EUMin}}$), the incentive rate ($\mathrm{DG_{IR}}$) and, eventually, the minimum annual energy based DG incentive ($\mathrm{DG_{IncMin}}$), can be obtained from equations (4.4) and (4.8) as:

$$\mathrm{DG_{IR}} = \frac{\mathrm{DG_{UC}} * (1+0.066-0.8) * \mathrm{WACC}}{(1-(1+\mathrm{WACC}))^{-\mathrm{nper}}}$$

$$\mathrm{DG_{IncMin}} = \mathrm{DG_{IR}} * \mathrm{DG_{EUMin}} * \mathrm{DG_{p,EnergyReq}}$$

By assuming that the required cost to reinforce the network components is £183,600 and the weighted average cost of capital (WACC) is 5.6%, the incentive rate and the minimum energy-based DG incentive for DNOs related to the connection of different DG technologies are presented in table 4.8.

Technology	**Energy req,DG**	**Energy max,DG**	$\mathbf{DG_{UC}}$	$\mathbf{DG_{IR}}$	$\mathbf{DG_{EUMin}}$	$\mathbf{DG_{IncMin}}$
	(MWh)	(MWh)	(£/MWh)	(£/MWh)		(£)
Biomass	4,317.23	31,930.20	5.75	0.021	13.52%	89.54
Geothermal	3,895.11	28,382.40	6.47	0.024	13.72%	92.25
Offshore Wind	2,578.22	15,255.54	12.03	0.054	16.90%	139.89
CCGT CHP	5,152.65	23,947.65	7.67	0.044	21.52%	226.75
Onshore Wind	3,543.59	12,417.30	14.79	0.113	28.54%	398.88
Solar PV	1,212.55	3,441.37	53.35	0.501	35.23%	608.06
Hydro	5,623.53	14,191.20	12.94	0.137	39.63%	769.11

Table 4.8 Minimum Threshold of DG Incentive for Various DG Technologies

As seen in table 4.8, the incentive rate of energy-based DG incentive ($\mathrm{DG_{IR}}$) depends on the unit cost of the incentive ($\mathrm{DG_{UC}}$). This relation can also be seen in equation (4.4). So that, the higher the unit cost, the higher the incentive rate. Meanwhile, the minimum threshold of energy-based DG incentive ($\mathrm{DG_{IncMin}}$) is related to the minimum DG energy utilization ($\mathrm{DG_{EUMin}}$), as written in equation (4.8). Hence, the higher the minimum DG energy utilization, the higher the minimum energy-based DG incentive for the DNOs.

For instances, the biomass technology will attract the lowest minimum threshold of energy-based DG incentive because it has the lowest DG energy utilization of 13.52%. While hydro technology, it will attract the highest minimum threshold of energy-based DG incentive because it has the highest energy utilization at 39.63%.

C). Maximum Threshold of Energy-based DG Incentive

As described in the previous section, the maximum threshold of energy-based DG Incentive will be given to the DNO if the maximum energy generation from the connected DG can be fully utilized, when DG energy utilization ($\mathrm{DG_{EU}}$) is equal to 100%, as written in equation (4.9) as:

$$\mathrm{DG_{IncMax}} = \mathrm{DG_{IR}} * 100\% * \mathrm{DG_{p,EnergyMax}}$$

By applying the above equation, the maximum thresholds of DG incentive for different DG technologies are presented in table 4.9.

Technology	**Energy conv,DG**	**Energy max,DG**	$\mathbf{DG_{UC}}$	$\mathbf{DG_{IR}}$	$\mathbf{DG_{EUMax}}$	$\mathbf{DG_{IncMax}}$
	(MWh)	(MWh)	(£/MWh)	(£/MWh)		(£)
Biomass	31,930.20	31,930.20	5.75	0.153	100,0%	4,897.86
Geothermal	28,382.40	28,382.40	6.47	0.173	100,0%	4,897.86
Offshore Wind	15,255.54	15,255.54	12.03	0.321	100,0%	4,897.86
CCGT CHP	23,947.65	23,947.65	7.67	0.205	100,0%	4,897.86
Onshore Wind	12,417.30	12,417.30	14.79	0.394	100,0%	4,897.86
Solar PV	3,441.37	3,441.37	53.35	1.423	100,0%	4,897.86
Hydro	14,191.20	14,191.20	12.94	0.345	100,0%	4,897.86

Table 4.9 Maximum Threshold of DG Incentive for Various DG Technologies

As presented in table 4.9, the maximum threshold of energy-based DG incentive is the same for all types of DG technology. This is related to the required reinforcement cost for connecting the DG to the network. Since the reinforcement cost is assumed to be the same for all types of DG technologies, the maximum threshold of energy-based DG incentive will also be the same for all types of DG technologies.

Further explanation for the relation between DG energy utilization and the thresholds of energy-based DG incentive can be seen in figure 4.8.

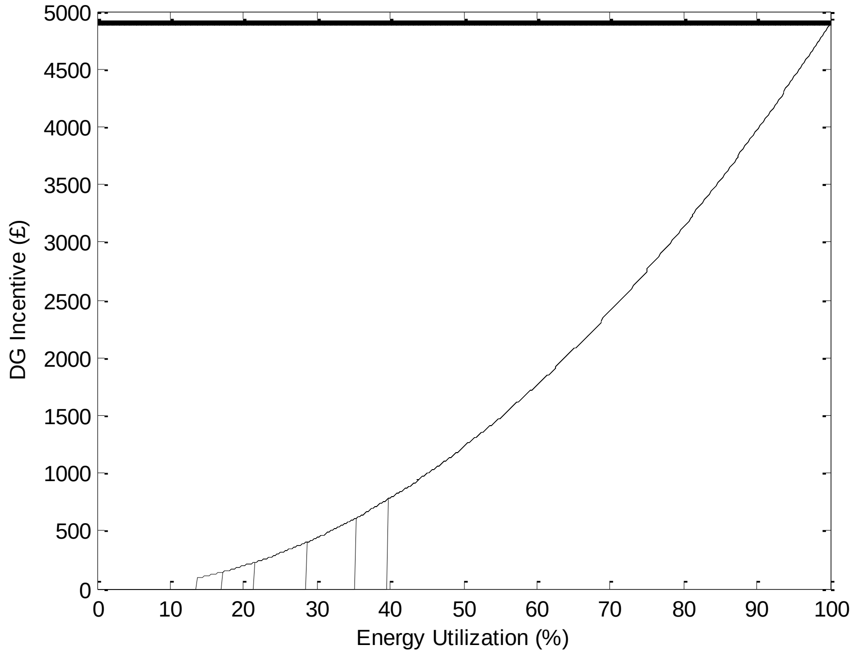

Figure 4.8 Energy Utilization vs DG Incentive for Various DG Technologies

Figure 4.8 shows that energy-based DG incentive will increase exponentially related to the increase of DG energy utilization.

In this case, if the DNO connected biomass technology DG, they will be required to utilize 13.52% of the maximum DG energy. This requirement will attract energy-based DG incentive for DNO as much as £89.54. If the connected DG is an onshore wind DG, the DNO will be required to utilize 28.54% of the maximum DG energy. As a result, DNO will receive energy-based DG incentive of £398.88. This means that the increase of DG energy utilization increases by 15% will cause an increase of the energy-based DG incentive by 345%.

If the utilization of DG energy reaches 100%, DNOs will receive the maximum energy-based DG incentive of £4,898.00. Compared with the lowest figure, this means that the increase of 86.48% of DG energy utilization will impact on the rise of energy-based DG incentive by 5,370%.

D). Risk Consideration Associated with DG Technologies

The deployment of distributed generation with renewable resources on electricity distribution network will impact on the security and reliability of the system [89]. Renewable energy resources, such as wind power and photovoltaics, are usually located in remote areas or separate from other power sources. This will require appropriate infrastructure to accommodate the connection. Also, the renewable resources will generate intermittent power to the grid, so that, it might increase the uncertainty into power system operation.

Moreover, the operation and performance of DGs which use renewable resources to generate energy will be strongly influenced by the environmental conditions, especially during extreme weather, which might deeply degrade or perhaps damage the network's components. The connection of DGs might cause technical problems, such as inacceptable voltage rises due to photovoltaics installation on the low voltage level and congestion issues related to the connection of wind farms [90].

4.2.7 Assessment of Energy-based DG Incentive Mechanism Associated with the Location of DG Connection

Figure 4.9 depicts three possible locations for an additional DG connection on the network with the distance of 3000m, 6000m and 9000m from the existing network. The location of DG connection will determine the investment cost to provide connection. The longer the network to build, the higher the investment cost to spend.

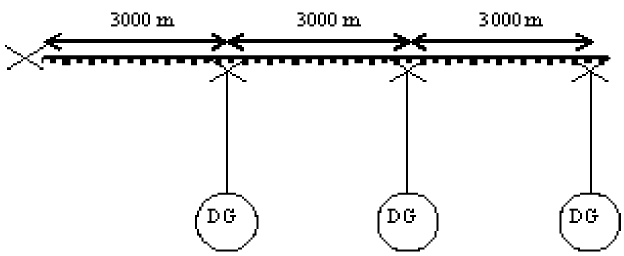

Figure 4.9 DG connection with different length of the network

A). Investment Costs

As previously explained, the considerably cost components are the shared-use connection assets. So, for the case shown in figure 4.9, each location has different investment costs, as shown in table 4.10. The cost estimation is based on Statement of Methodology and Charges for Connection [77][78].

Cost Components	Lines Length		
	3000m	6000m	9000m
Shared-Use Connection Assets			
2 HV Circuit Breakers at Primary substation @51,800.00	£103,600.00	£103,600.00	£103,600.00
Installation of a HV overhead line @	£80,000.00	£160,000.00	£240,000.00
Total Reinforcement Cost	£183,600.00	£263,600.00	£343,600.00

Table 4.10 Cost Components for Different Length of Network's Line

B). The Minimum Threshold of Energy-based DG Incentive

The new DG is assumed to be an onshore wind generation. The capacity of DG is 4.5MVA with power factor of 0.9, capacity factor of 0.35, operational time of 8760 hours/year and the levelised cost of energy generation of £75/MWh.

In order to determine the minimum threshold of energy-based DG incentive for those three possible locations, the same calculation steps in the previous case are applied. The results are presented in table 4.11.

Line's Length	**Energy req,DG** (MWh)	**Energy max,DG** (MWh)	$\mathbf{DG_{UC}}$ (£/MWh)	$\mathbf{DG_{IR}}$ (£/MWh)	$\mathbf{DG_{EUMin}}$	$\mathbf{DG_{IncMin}}$ (£)
3000m	2,448.00	12,417.30	14.79	0.39	19.71%	190.36
6000m	3,514.67	12,417.30	21.23	0.57	28.30%	563.37
9000m	4,581.33	12,417.30	27.67	0.74	36.89%	1,247.72

Table 4.11 The Minimum Threshold of Energy-based DG Incentive for Onshore Wind Technology with Different Length of Network's Line

Table 4.11 shows that the increase of the minimum threshold of energy-based DG incentive ($\mathrm{DG_{IncMin}}$) is related to the increase of the unit cost of the incentive ($\mathrm{DG_{UC}}$) and the minimum DG energy utilization ($\mathrm{DG_{EUMin}}$).

In this case, the increase of the line's length by 3000m will increase the reinforcement cost by £80,000.00. Because of this, the unit cost of the incentive will increase by £6.44/MWh. As a result, the incentive rate will increase by £0.17/MWh.

Meanwhile, the relation between the minimum DG energy utilization and the minimum threshold of energy-based DG incentive can be explained further using the graph in figure 4.10.

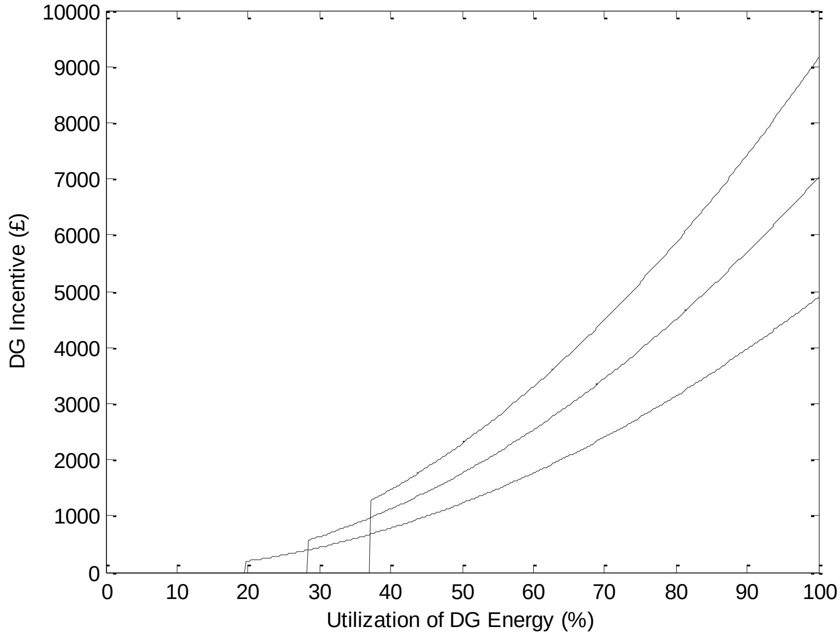

Figure 4.10 Energy Utilisation vs DG Incentive for Different Line's Length

As depicted in figure 4.10, the DG energy utilization has an exponential relation with the energy-based DG incentive. So, the energy-based DG incentive will exponentially increase in accordance with the increase of the DG energy utilization.

Referring to the case study, the increase of £80,000.00 of reinforcement cost will increase the minimum DG energy utilization by 8.59%, which will result in an increase of the minimum threshold of energy-based DG incentive by £373.01. However, when the minimum DG energy utilization increase by 17.18%, the minimum threshold of energy-based DG incentive will increase by £1,057.36.

C). The Maximum Threshold of Energy-based DG Incentive

The Maximum Thresholds of energy-based DG Incentive for three possible locations for DG connection are presented in table 4.12.

Line's Length	**Energy conv,DG**	**Energy max,DG**	$\mathbf{DG_{UC}}$	$\mathbf{DG_{EUMax}}$	$\mathbf{DG_{IR}}$	$\mathbf{DG_{IncMax}}$
	(MWh)	(MWh)	(£/MWh)		(£/MWh)	(£)
3000m	12,417.30	12,417.30	14.79	100%	0.39	4,897.86
6000m	12,417.30	12,417.30	21.23	100%	0.57	7,032.01
9000m	12,417.30	12,417.30	27.67	100%	0.74	9,166.15

Table 4.12 The Maximum Threshold of Energy-based DG Incentive for Onshore Wind Technology with Different Length of Network's Line

As presented in table 4.12, the maximum threshold of energy-based DG incentive increases in association with the increase of the line's length. The longer the line's length, the higher the required reinforcement cost. As a result, the maximum threshold of the incentive for the DNOs will be higher as well.

From the results given in table 4.12, the increase of the line's length by 3000m will increase the reinforcement by £80,000.00. As a result, this will impact on the increase of the maximum threshold of energy-based DG incentive by £2,134.14. Referring to this case, the increase of energy-based DG incentive is estimated to be £711.38/km for the connection of 4.5MVA onshore wind generation.

4.2.8 Assessment of Energy-based DG Incentive Mechanism Associated with the Network Configuration

This section describes the impact of network configuration on determining the energy-based DG incentive for the DNOs. For the case study, a 4.5MVA onshore wind generation will be connected to the network. The possible location for this new connection is at one of two generation-dominated area busbars, i.e. Bus11-2 or Bus11-6. The impact of DG connection on those two busbars has been explained in chapter 3.

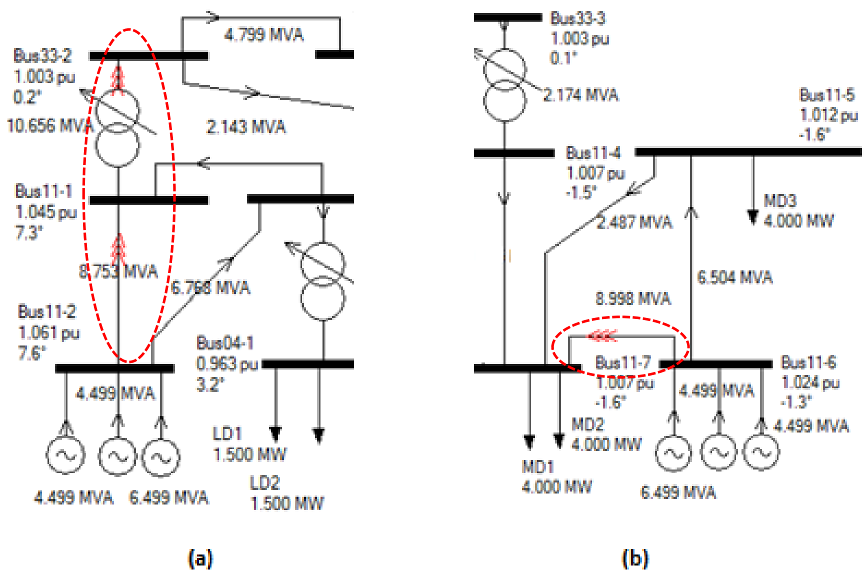

Figure 4.11 Impact of new DG connection: (a) At Bus11-2 and (b) At Bus11-6

Figure 4.11 shows the impact of connecting a new DG to one generation-dominated areas, i.e. Bus11-2 and Bus11-6. DG connection at Bus11-2 will cause two components of the network, i.e. the line between Bus11-2 and Bus11-1 and the transformer located between Bus11-1 and Bus33-2, to be overloaded. This connection increases the power which is flowing through those two components to exceed the standard capacity of the components. While the new DG connection at Bus11-6, it will impact on overloading of the line between Bus11-6 and Bus11-7. In order to deal with the problem, in this case, the DNO decides to reinforce the network in order to accommodate the full capacity of the new DG connection.

A). DG Configuration

At Bus11-2, there are two DGs that are already connected, both are hydro generations with power factor of 0.9, capacity factor of 0.40 and levelised cost of energy generation of £42/MWh. One DG is a 4.5MVA generator and the other one is 6.5MVA. The new DG that will be connected to the network is a 4.5MVA wind generation with power factor of 0.9, capacity factor of 0.35 and levelised cost of energy generation of £75/MWh.

In order to simplify the comparison, it is assumed that DG configuration at Bus11-6 is similar to at Bus11-2.

B). Network Reinforcement Cost

In order to accommodate all DG capacity that will be connected either to Bus11-2 or Bus11-6, the DNO needs to upgrade the network components on the overloaded lines or branches. The details of the costs needed to reinforce the network are presented in table 4.13. The cost estimation is based on Statement of Methodology and Charges for Connection [77][78].

COST COMPONENTS	Bus11-2	Bus11-6
Sole-Use Connection Assets		
Feasibility Studies	£2,080.00	£2,080.00
Assessment and Design for all relevant work	£1,893.00	£1,893.00
Assessment and Design of the Non-Contestable Work	£1,320.00	£1,320.00
Design Approval of the Contestable Work	£553.00	£553.00
Final Works and Phased Energisation	£1,342.00	£1,342.00
Inspection and Monitoring - HV Network Site Visit	£3,168.00	£3,168.00
Land Rights	£1,880.00	£1,880.00
Contestable Work		
Installation of a 500m HV cable	£41,500.00	£41,500.00
HV circuit Breaker at customer substation	£30,000.00	£30,000.00
Actuators and Remote Control (RTU)	£16,000.00	£16,000.00
Sub Total	**£99,736.00**	**£99,736.00**
Shared-Use Connection Assets		
Non-Contestable Work		
2 HV Circuit Breakers at Primary substation @51,800.00	£103,600.00	£103,600.00
Upgrading a 3000m HV overhead line	£80,000.00	£80,000.00
Upgrading the existing outdoor substation	£515,000.00	
Sub Total	**£698,600.00**	**£183,600.00**

Table 4.13 The Cost Components for Network Reinforcement

As previously explained, the expenses for the sole-use connection assets will be directly refunded from the customer through connection charges, so that, the DG incentive calculation is based on the shared-use connection assets. From the table, the investment cost needed to reinforce the network, as a result of DG connection at Bus11-2, is £698,600.00. While DG connection at Bus11-6 requires network reinforcement cost of £183,600.00.

C). Minimum Threshold of Energy-based DG Incentive

Assuming that the new DG which will be connected either to Bus11-2 or Bus11-6 is a 4.5MVA wind generation, with power factor of 0.9, capacity factor of 0.35, the operational time of 8760 hours/year and the levelised cost of energy generation of £75/MWh.

In order to determine the minimum threshold of energy-based DG incentive for those two network configurations, the same calculation steps in the previous case are applied. The minimum thresholds of energy-based DG incentive for DG connection at the two designated busbars are presented in table 4.14.

Location	**Energy req,DG**	**Energy max,DG**	$\mathbf{DG_{UC}}$	$\mathbf{DG_{IR}}$	$\mathbf{DG_{EUMin}}$	$\mathbf{DG_{IncMin}}$
	(MWh)	(MWh)	(£/MWh)	(£/MWh)		(£)
Bus11-6	3,543.60	12,417.30	14.79	0.39	28.54%	398.88
Bus11-2	10,754.76	12,417.30	56.26	1.50	86.61%	13,980.08

Table 4.14 The Minimum Threshold of Energy-based DG Incentive for Different Network Configuration

Given the DG connection at Bus 11-2 requires reinforcement cost almost four times higher than the connection at Bus11-6, the unit cost of energy-based DG incentive (DG_{UC}) for DG connection at Bus11-2 will be as higher as four times that the one for DG connection at Bus11-6. As a result, the incentive rate (DG_{IR}) and the minimum DG energy utilization ($\mathbf{DG_{EUMin}}$) will increase by approximately four times, as presented in table 4.14.

Meanwhile, the relation between the minimum DG energy utilization and the minimum threshold of energy-based DG incentive can be explained further using the graph in figure 4.12.

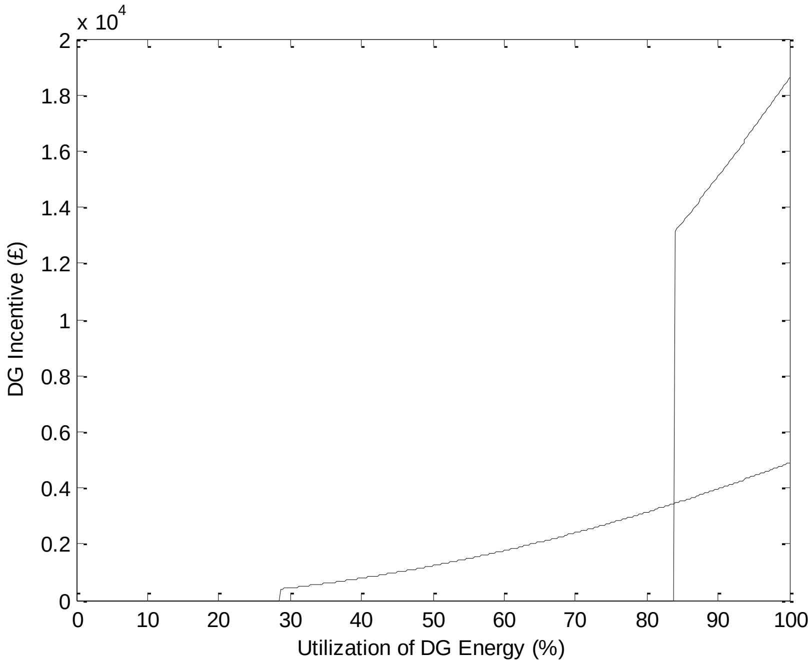

Figure 4.12 Impact of Network Configuration on Energy Utilization and DG Incentive

As depicted in figure 4.12, the minimum threshold of energy-based DG incentive will increase exponentially as a result of the increase in reinforcement cost. The increase of reinforcement cost by four times from the initial one will cause the increase of the DG energy utilization from 28.54% to 86.61%. However, this will trigger the rise of the minimum energy-based DG incentive by approximately thirty five times, from £398.88 to £13,980.08.

D). The Maximum Threshold of Energy-based DG Incentive

The Maximum Thresholds of Energy-based DG Incentive for DG connection at Bus11-2 and Bus11-6 are presented in table 4.15.

Location	**Energy conv,DG (MWh)**	**Energy max,DG (MWh)**	$\mathbf{DG_{UC}}$ **(£/MWh)**	$\mathbf{DG_{EUMax}}$	$\mathbf{DG_{IR}}$ **(£/MWh)**	$\mathbf{DG_{IncMax}}$ **(£)**
Bus11-6	12,417.30	12,417.30	14.79	100%	0.39	4,897.86
Bus11-2	12,417.30	12,417.30	56.26	100%	1.50	18,636.42

Table 4.15 The Maximum Threshold of Energy-based DG Incentive for Different Network Configuration

As shown in table 4.15, the maximum threshold of energy-based DG incentive increases in association with the increase of the reinforcement cost. The increase of reinforcement cost by almost four times from the initial one will increase the maximum energy-based DG incentive also by four times, approximately, from £4,897.86 to £18,636.42

4.3 COMPARISON BETWEEN ENERGY-BASED AND CAPACITY-BASED DG INCENTIVES

The comparison between the proposed mechanism, i.e. energy-based DG incentive and current mechanism, i.e. capacity-based mechanism can be seen in table 4.16. The comparison is based on the assumption that the new connected DG has the capacity of 4.5MVA with the power factor of 0.9.

By considering three factors which might impact DG connection, including the DG technology, the location and the network configuration, the energy-based DG incentive for each case is presented in table 4.16, based on the assessment in section 4.2.6.

Meanwhile, the calculation of capacity-based DG incentive is based on the explanation in in chapter 2, i.e. the DNOs will receive £1/kW of total connected DG capacity. Hence, for the case of connecting 4.5MVA (which is equal to 4.05MW) DG, the DNOs will receive incentive of £4,050.00.

Considered Factor	Type	DG_{EUMin}	Energy-based DG Incentive		Capacity-based DG Incentive (£)
			Min Threshold (£)	Max Threshold (£)	
DG Technology	Biomass	13.52%	89.54	4,897.86	4,050.00
	Geothermal	13.72%	92.25	4,897.86	4,050.00
	Offshore Wind	16.90%	139.89	4,897.86	4,050.00
	CCGT CHP	21.52%	226.75	4,897.86	4,050.00
	Onshore Wind	28.54%	398.88	4,897.86	4,050.00
	Solar PV	35.23%	608.06	4,897.86	4,050.00
	Hydro	39.63%	769.11	4,897.86	4,050.00
Location	3000m	19.71%	190.36	4,897.86	4,050.00
	6000m	28.30%	563.37	7,032.01	4,050.00
	9000m	36.89%	1,247.72	9,166.15	4,050.00
Network Configuration	Bus11-6	28.54%	398.88	4,897.86	4,050.00
	Bus11-2	86.61%	13,980.08	18,636.42	4,050.00

Table 4.16 Comparison between Energy-based and Capacity-based DG Incentives

As presented in table 4.16, there are three factors that must be considered in determining the value of energy-based DG incentive for DNOs, i.e. the DG technology, the location of DG connection and the network configuration.

In terms of DG technology, the minimum threshold of energy-based DG incentive depends on the minimum energy utilization of each DG technology (DG_{EUMin}), which is largely determined by the parameters attached on each type of DG technology, including capacity factor, operational time and levelised cost of energy generation. As seen in table 4.14, the lowest value of the minimum energy utilization of each DG technology (DG_{EUMin}) is for biomass technology at 13.52%, while the highest value is for hydro technology at 39.63%. As the results, biomass technology has the lowest DG incentive minimum threshold of £89.54 and hydro technology has the highest one of £769.11. Meanwhile, the maximum threshold of energy-based DG incentive is the same for all DG technologies since it will be given if the available DG energy can be fully utilized (i.e. at DG_{EUMax} = 100%).

In terms of the location of DG connection, the minimum threshold of energy-based DG incentive increases in accordance with the increase of the distance of DG location. The further the location of DG connection, the higher the required reinforcement cost. As a result, the minimum threshold of energy-based DG incentive will be higher. The location of DG connection also impacts on the maximum threshold of the incentive since it will determine the required reinforcement cost. As the reinforcement cost increased, the incentive will increase as well.

Meanwhile, the configuration of a network can determine the impact of DG connection, in terms of how many network components that might be affected and need to be upgraded. The more the affected network components, the higher the required cost. As a result, the incentive will be higher, too.

4.4 CHAPTER SUMMARY

This chapter describes two mechanisms which can be applied to deal with the connection of a new DG at a generation-dominated area/busbar, i.e. DG curtailment mechanism and network reinforcement mechanism. The impact of both mechanisms on the voltage level, network capacity utilization and power losses of the network can be summarized as follow:

- Both DG curtailment and network reinforcement mechanisms can reduce the voltage level of the related busbars. The decrease of voltage level due to DG curtailment can reach 2.1% from the initial level, while network reinforcement mechanism will decrease the initial voltage level down to 0.4%. The largest reduction occurs on the targeted busbar, where the DG is connected.
- In a generation-dominated area, DG curtailment mechanism will reduce the power flow of the related lines, so that, it will reduce the network capacity utilization of those lines. As examined in the case study, the network capacity utilization can be reduced down to 77.6%. Meanwhile, network reinforcement mechanism, which is done by upgrading the capacity of the line, will decrease the network capacity utilization down to 82.1%.

- Both mechanisms also impact on the reduction of the power losses of the related lines. DG curtailment mechanism can contribute in the reduction of power losses by 40.1%, while network reinforcement mechanism can contribute in the reduction of power losses by 22%.

This chapter also describes the development of energy-based DG incentive mechanism which aims to incentivise DNOs in providing DG connection on their distribution networks. The following points explain the summary of this mechanism:

- Energy-based DG incentive mechanism is based on the utilization of DG energy and its relation with the required investment cost to provide connection.
- The minimum threshold of the energy-based DG incentive is given to the DNOs when the connected DGs convey the minimum required energy. If they cannot meet this requirement, the incentive for DNOs is equal to 0. Meanwhile, the maximum threshold of the incentive is given when the available DG energy can be fully utilized.
- Since different DG technologies generate different energy output, the minimum requirement for energy to be conveyed for each DG technology will be vary. However, for the same DG capacity, the maximum threshold of the incentive will be the same, as long as the available DG energy can be fully utilized.
- The location of DG connection on the network will impact the required investment cost to provide connection. The further the location of DG connection, the higher the required investment cost. As the result, the minimum and maximum thresholds of the incentive will be higher.
- The network configuration can contribute in determining the number of components which might be affected or congested due to additional DG connection. The higher the number of congested components, the higher the required investment cost to provide connection. Consequently, this will result in higher incentive for the DNOs.
- Comparing with current incentive mechanism, energy-based DG incentive can reflect the effectiveness of DNOs to deal with the required investments in association with DG connection on their network.

5 EFFECTIVE DSR INCENTIVE FOR DISTRIBUTION NETWORK OPERATORS

For distribution network operators, there are two main objectives of implementing demand side response. The first objective is to avoid excessive demand at peak times, in which this may lead to the need of network reinforcement. The second one is to deal with pre-fault and post-fault management on the distribution network, to reduce the time for customers not being supplied. Also, in longer terms, distribution network must accommodate the possible fast growth of electric vehicles, heat pumps and thermal storage [45].

It is predicted that electricity will be used in transport and heating sectors, which tend to be flexible in electricity consumption, in the future. Meanwhile, wind, wave and tidal, as electricity generation sources, are variety in their output and inflexible in term of time to generate. This combination, i.e. high penetration of DGs combined with high penetration of flexible demand, requires a dynamic relationship between supply and demand in distribution level [45].

To deal with the challenge, the Demand Side Response (DSR) mechanism [14], a mechanism to manage the consumption of electricity in response to the conditions of electricity supply, may have a greater opportunity to apply. DSR can be used to reduce peak demand, as well as to respond the requirement to balance the system due to the demand is greater than the supply, by running on-site generation. Facilitating DSR on the distribution networks, however, require a financial incentive, as a consequent.

Various incentive mechanisms for DNOs to promote DSR have been trialled and applied in different countries, including demand management incentive mechanism, shared savings mechanism, rate of return mechanism and avoided cost mechanism [25][26]. These mechanisms can be classified into two categories. The first category includes the incentive mechanisms which allow DNOs to recover the investment costs and forgone revenues due to DSR implementation, such as applied in demand management incentive and avoided cost mechanisms. The second category includes the incentive mechanisms which allow DNOs to receive compensation as a result of implementing DSR, such as applied in shared savings and rate of return mechanisms.

Currently, the existing DSR incentive mechanisms are operated independently without any correlation between them. Therefore, this research proposes a new DSR incentive mechanism, called energy-based DSR incentive, which allows DNOs to recover their investment costs by considering the utilization of available DSR energy on the network.

5.1 IMPLEMENTATION OF ENERGY-BASED DSR INCENTIVE

5.1.1 Principles of the Energy-Based DSR Incentive

Energy-based DSR Incentive mechanism is developed to incentivise DNOs in facilitating DSR implementation on their distribution networks. The incentive is based on the utilization of available DSR capacity on the network, i.e. it depends on how much energy can be utilised from DSR participants. The higher the energy participation, the higher the incentive for the DNOs. The maximum threshold of the incentive will be given to the DNOs if they can fully utilize the available DSR participation, as required.

5.1.2 Structure of the Energy-based DSR Incentive

The structure of the proposed energy-based DSR incentive adopts the hybrid mechanism as applied for energy-based DG incentive, i.e. giving DNOs a partial pass-through treatment and additional incentive rate to implement DSR programme on their distribution network.

1). Level of Pass-through

Energy-based DSR incentive mechanism also adopted the pass-through mechanism which is applied in energy-based DG incentive mechanism, i.e. by allowing DNOs to pass 80% of their DSR investment cost on to the customers who participate in the DSR programme.

2). Energy-based DSR Incentive Rate

The energy-based DSR incentive rate is developed from the remaining 20% of DSR investment cost and is annuitized for a particular period of time. The period of time is assumed to be 15 years, as the assumed life time of DSR components.

3). Incentive Thresholds

The maximum threshold of the incentive will be given to the DNOs if the available DSR energy on the network can be fully utilized, as required. Contrary, if the available DSR energy is not utilized, the DNOs will not be incentivised.

5.1.3 Methodology to Develop Energy-Based DSR Incentive

The methodology used to develop energy-based DG incentive mechanism can be explained by using the flowchart depicted in figure 5.1 (the details can be seen in appendix 3).

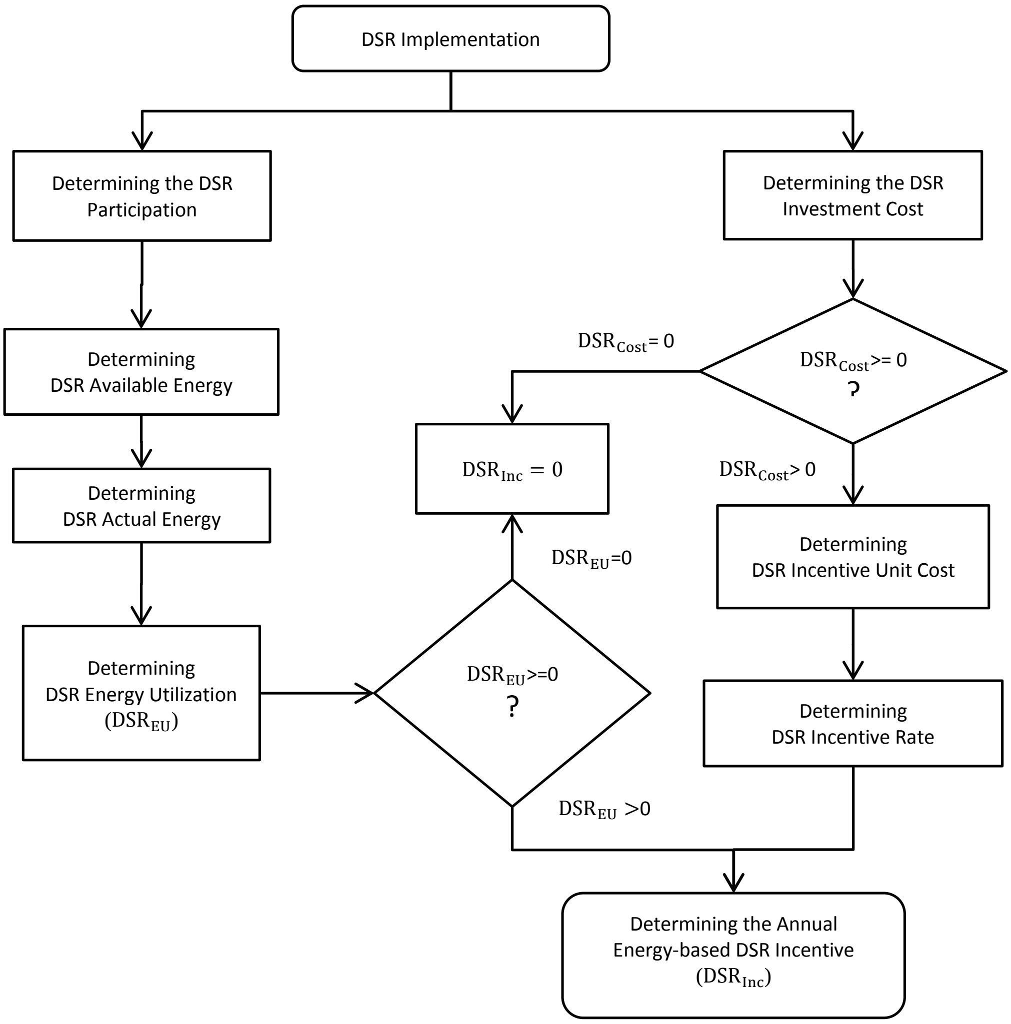

Figure 5.1 Flowchart for Energy-based DSR Mechanism

The methodology to develop energy-based DSR Incentive mechanism can be explained as follows.

A. Determining the Investment Cost of a DSR Project

The costs to implement DSR in the electricity distribution network can be categorized in two types, i.e. participant costs and system costs [17]. Participant costs are any associated costs that must be borne by the customers who are participating in DSR programme. While the system costs, are described as the costs that will be borne by the distribution network operators to implement DSR.

Type of Cost		Cost	Quantification
Participant Costs	Initial costs	Enabling technology investment	Mainly
		Establishing response plan or strategy	No
	Event specific costs	Comfort/inconvenience costs	No
		Reduced amenity/lost business	No
		Rescheduling costs (e.g. overtime pay)	No
		Onsite generator fuel and maintenance costs	No
System Costs	Initial costs	Metering/communication system upgrades	Yes
		Utility equipment or software costs, billing system upgrades	Partial
		Consumer education	Partial
	Ongoing programme costs	Programme administration/management	Partial
		Marketing/recruitment	Partial
		Payments to participating customers	Partial
		Programme evaluation	No

Table 5.1 Different Cost Categories for DSR Implementation [17]

Table 5.1 does not provide quantitative estimates for all associated costs, only 'enabling technology investment' is quantified. Enabling technology investment, which falls into participant costs, is actually a system cost since suppliers have a mandate to install smart meters for the domestic and small and medium non-domestic sectors. However, this cost will directly be passed on to end users. Other than technology cots, the remaining costs are remaining un-quantified. Meanwhile, regarding the system costs, most of the costs which fall onto these categories are able to quantify. Only programme evaluation cost is remaining un-quantified.

However, in practice, the costs needed in implementing DSR programme is unique to each situation, depends on the nature of the DSR, in terms of its reliability, availability and its duration . These elements, then, will be factored to establish the DSR costs [57]. Likewise, the breakdown of DSR Project Cost Category varies between one project and another. One project might include a particular cost into a particular category, based on their classification. This can be seen in the description of each sub category from three DSR trial projects in the UK, i.e. Capacity to Customer (C2C) Project, Low Carbon London Project and New Thames Valley Vision Project, which is presented in table 5.2.

Cost Category	Sub Cost Category		
	C2C Project	**Low Carbon London Project**	**New Thames Valley Project**
Employment/ Labour Costs	Monitoring Equipment Installation - Labour	Programme Director	Project and ICT management
	Business & CIO System Design Approval	Project Management Others	Project engineering
	Connections	Communications & Commercial Managers	Network Field Resources
	Dissemination	Administrative Support	knowledge management
	Project Management	Technical Lead	
Equipment Costs	Publicity Materials	5 ANM schemes	monitoring equipment
	Remote Control Installation	40 aggregator equipment	Communications
	Monitoring Equipment Installation	smart metering	Battery storage and thermal storage
	Commissioning SCADA link to Remote Control Devices	Plugged in Places contribution	Integration of monitoring, modelling and management
	IT hardware and software	Substation works	Automatic demand response equipment
Contractors/ Collaborator Labour Costs	Demand Side Response Customer Survey	Partner/Collaborator labour costs	LV & HV network monitoring installation
	Remote Control Installation at Customers' Premises		Battery storage installation
	Contractors Travel & Publicity - Informing Affected Customers		Communications
	Carbon Analysis		Smart analytics
	Data Analysis and Economic Modelling		Learning dissemination,
	Power System and Technical Modelling		Integration activities to support DNO business as usual
IT Costs	Data Capture and Cleanse	operational data store	Integration of monitoring, modelling and management
	Database Licenses	Carbon Tool licensing	ICT Field Architecture
	Interface Development	SGS support & software licence	ICT Field Resource
	Develop Real-time Data Update Functionality	Aggregator IT costs	Real-time systems and information technology equipment
	System Integration & Testing	comms, infrastructure, environment and interfaces	
	Testing and Development Workstation	Logica head end	
Payment to Users	Payment to Users	Payment to Users	Payment to Users
Other Costs	Publicity and Dissemination	Contingency	Land
	Accommodations	Abnormal travel	Learning dissemination, website and low carbon community centre
	Unplanned interruptions during trial	Public engagement/learning dissemination	Real-time systems and information technology equipment
	Contingency	Inflation	Contingency

Table 5.2 Sub Cost Categories from Different DSR Projects [82] [83] [84]

As presented in table 5.2, there are five cost categories in each DSR trial project, including employment cost, equipment cost, contractor cost, IT cost, payment to users and other costs. By considering these five cost categories, the costs breakdown of each DSR trial project are presented in table 5.3.

Cost Category	**DSR Projects**					
	C2C		**Low Carbon London**		**New Thames Valley Vision**	
	(£ k)	**(%)**	**(£ k)**	**(%)**	**(£ k)**	**(%)**
Employment Cost	2,512	24.4%	4,594	15.4%	5,932.76	22.1%
Equipment Cost	3,078	30.0%	4,640	15.5%	4,526.44	16.9%
Contractors Cost	2,254	21.9%	7,007	23.4%	8,710.71	32.5%
IT Cost	740	7.2%	3,935	13.2%	5321.70	19.9%
Payments to Users	300	2.9%	2,440	8.2%	591.00	2.2%
Other Costs	1,392	13.5%	7,272	24.3%	1,715.60	6.4%
TOTAL	10,276	100.0%	29,888	100.0%	26,798.21	100.0%

Table 5.3 Example of DSR Projects Cost Breakdown [82] [83] [84]

B. Determining DSR Available Capacity

DSR available capacity, $\mathrm{DSR_{CapAv}}$, is defined as the amount of DSR capacity which is available to response to the supply condition in the system. The unit of DSR available capacity is expressed in megawatts (MW).

The available DSR capacity might come from the customers who are participating in DSR programme through one of three possible ways, including demand reduction, demand shifting and running on-site generation mechanisms. The participants of DSR programme need to sign a contract with the associated DNO whether they are willing to reduce their electricity consumption, to shift their use of electricity, or to run their on-site generation whenever required by the DNO. So, there is a guarantee that the DNO has sufficient amount of available DSR capacity that can be used to deal with the changes in supply provision in the distribution system.

C. Determining DSR Energy Utilization

DSR energy utilization, $\mathrm{DSR_{EU}}$ (expressed %), is obtained from the comparison of the actual DSR energy participation, $\mathrm{DSR_{EAc}}$ (expressed in MWh), with the available DSR energy on the network, $\mathrm{DSR_{EAv}}$ (expressed in MWh), which can be written as:

$$\mathrm{DSR_{EU}} = \frac{\mathrm{DSR_{EAc}}}{\mathrm{DSR_{EAv}}} \quad ..(5.1)$$

The $\mathrm{DSR_{EAc}}$ and $\mathrm{DSR_{EAv}}$ can be derived by multiplying the actual DSR capacity participation, $\mathrm{DSR_{CapAc}}$ (expressed in MW), and the available DSR capacity,

DSR_{CapAv} (expressed in MW), by a particular period of time, $time_{req}$ (expressed in hrs), as required by the DNOs. Hence, equation (5.1) can be expressed as:

$$DSR_{EU} = \frac{DSR_{CapAc} * time_{act}}{DSR_{CapAv} * time_{req}} \qquad ..(5.2)$$

In a case where not all DSR participants can participate when required by the DNOs, the amount of DSR energy that cannot be utilised, $DSR_{Unutilised}$ (expressed in MWh), can be obtained from:

$$DSR_{Unutilised} = (DSR_{CapAv} - DSR_{CapAc}) * time_{req} \qquad ..(5.3)$$

Hence, the DSR energy utilization can also be written as

$$DSR_{EU} = \frac{(DSR_{CapAv} - DSR_{Unutilised}) * time_{req}}{DSR_{EAv}} \qquad ..(5.4)$$

D. Determining the Unit Cost of DSR Incentive Rate

The firs parameter that must be calculated is the unit cost of the DSR incentive, DSR_{UC} , which is expressed in £/MWh. This unit cost is derived from the cost of DSR project, DSR_{Cost} (expressed in £) divided by the DSR available energy, DSR_{EAv} (expressed in MWh), which can be written as:

$$DSR_{UC} = \frac{DSR_{Cost}}{DSR_{EAv}} \qquad ..(5.5)$$

E. Determining Energy-Based DSR Incentive Rate

DSR incentive rate, DSR_{IR} (expressed in £/MWh), can be calculated by considering the DSR unit cost, the DNOs rate of returns including weighted average cost of capital (WACC) and additional rate of return, and the lifetime of DSR equipment (nper), as follows:

$$DSR_{IR} = \frac{DSR_{UC} * (1 - 80\% + WACC + additional\ rr) * WACC}{(1 - (1 + WACC))^{-nper}} \qquad ..(5.6)$$

F. Determining Annual Energy-Based DSR Incentive

Therefore, the annual DSR Incentive, DSR_{Inc} (expressed in £), can be obtained by multiplying the DSR incentive rate , DSR_{IR} (expressed in £/MWh), with the actual DSR energy participation, DSR_{EAc}, which is expressed in MWh.

$$DSR_{Inc} = DSR_{IR} * DSR_{EU} * DSR_{EAc} \qquad ..(5.7)$$

G. Determining the Maximum Threshold of Energy-Based DSR Incentive

The maximum threshold of energy-based DSR incentive, $\text{DSR}_{\text{IncMax}}$ (expressed in £), will be given to the DNOs if the available DSR energy participation, DSR_{EAv} (expressed inMWh), can be fully utilised as required, i.e. when $\text{DSR}_{\text{EUMAx}}$ = 100%, and written as:

$$\text{DSR}_{\text{IncMax}} = \text{DSR}_{\text{IR}} * \text{DSR}_{\text{EUMAx}} * \text{DSR}_{\text{EAv}}$$

$$\text{DSR}_{\text{IncMax}} = \text{DSR}_{\text{IR}} * 100\% * \text{DSR}_{\text{EAv}} \quad ..(5.8)$$

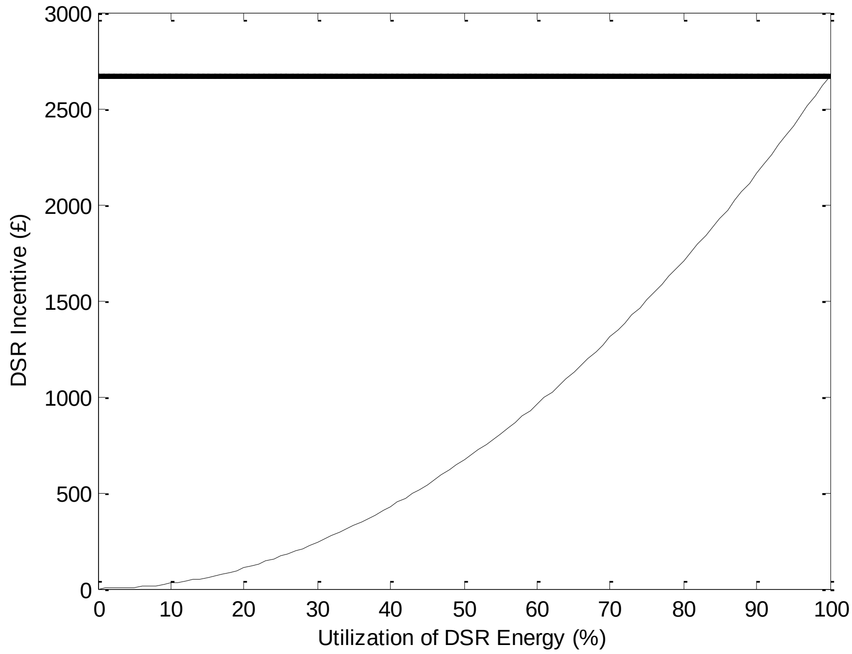

Figure 5.2 DSR Energy Participation vs DSR Incentive

The graph depicted in figure 5.2 shows the relation between DSR energy participation and the amount of energy-based DSR incentive for DNOs. The energy-based DSR incentive will increase exponentially in accordance with the increase of DSR energy utilization. The maximum threshold of energy-based DSR incentive is given to the DNOs if the available DSR energy can be fully utilized, i.e. when DSR energy utilization is equal to 100%.

5.2 CASE STUDIES

The case study is based on the data and information taken from two DSR projects which have been trialled in the UK, i.e. the Honeywell I&C ADR: Demonstrating the Functionality of Automated Demand Response project and the Low Carbon London project.

5.2.1 Case Study 1

The data for the first case study is taken from the Automated Demand Response (ADR) project. This DSR trial project was implemented in three buildings, including a typical public sector building, a typical education sector building and a typical commercial building. The aim of the project is to investigate the basic functionality of Automated Demand Response.

A. DSR Investment Cost

The ADR project is run by Scottish and Southern Energy Power Distribution, one of DNOs in the UK. The breakdown of project cost is presented in table 5.4. All cost categories fall under DNO's responsibility.

Cost Category	£
Contractor (Honeywell)	219,900.00
Project Management	23,000.00
Overheads	3,000.00
Contingency	15,000.00
Total	260,900.00

Table 5.4 DSR Costs for Case Study 1 [46]

B. Available DSR Capacity

The available DSR capacity is determined by the capacity in which customers are willing to participate in DSR programme. The participants and their available capacity for Honeywell I&C ADR Project are presented in table 5.5.

Premises	Equipment	Rating Capacity (kW)
Honeywell House Building (Commercial Building)	Air Handling Units	187.0
	Chillers	7.4
	Boilers	3.7
	Sub Total	198.1
Bracknell & Wokingham (B&C) College (Education Sector Building)	Air Handling Units	98.9
	Chillers	66.1
	Lifts	35.3
	Extract Fans	5.5
	DX Split Unit	2.5
	Heat Pump	35.1
	Sub Total	243.4
Bracknell Forest Council's Time Square (Public Sector Building)	Fan Coil Units (120 x @2.9kW)	348.0
	Chiller	66.1
	Sub Total	414.1
Total		855.6

Table 5.5 The Available DSR Capacity for Case Study 1 [46]

During the project trial in spring 2012, each DSR event was carried out for one hour, between 3pm and 8pm. The event was scheduled in advance. The participants were notified at least two working days before the event took place. Given one hour period of each DSR event, the estimated available DSR energy that can be participated is presented in table 5.6.

Building	**Available DSR Capacity (kW)**	**DSR event period of time (hours)**	**Number of Days in Spring Season**	**Available DSR Energy (kWh)**
Commercial Building	198.1	1	91	18,027.1
Education Sector Building	243.4	1	91	22,149.4
Public Sector Building	414.1	1	91	37,683.1
Total				77,859.6

Table 5.6 The Available DSR Energy for Case Study 1

C. DSR Energy Utilization

The actual DSR energy participation from the customers who participate in Honeywell I&C ADR Project, which is run during spring season in 2012, can be calculated by using equation (5.2) as:

$$\mathrm{DSR_{EAc}} = \mathrm{DSR_{CapAc}} * \mathrm{time_{act}}$$

Hence, the DSR energy utilization, $\mathrm{DSR_{EU}}$, can be obtained by using equation (5.1) as:

$$\mathrm{DSR_{EU}} = \frac{\mathrm{DSR_{EAc}}}{\mathrm{DSR_{EAv}}}$$

Building	**Actual DSR Capacity (kW)**	**Actual DSR Energy (kW)**	**Available DSR Energy (kWh)**	**DSR Energy Utilization (%)**
Commercial Sector Building	92.0	8,372.0	18,027.1	10,8%
Education Sector Building	48.0	4,368.0	22,149.4	5,6%
Public Sector Building	11.2	1,019.2	37,683.1	1,3%
Total		13,759.2	77,859.6	17.67%

Table 5.7 DSR Energy Utilization for Case Study 1

As presented in table 5.7, the actual DSR participation is quite low. The contribution from commercial sector building is around 10.8%, education sector building contributes 5.6% and public sector building contributes 1.3% from the available DSR energy on the network. So, in total, the DSR energy utilization is around 17.67%.

D. Unit Cost of DSR Incentive

Given the DSR investment cost of £260,900.00 and the available DSR energy on the network is around 77,859kWh, the unit cost of DSR incentive for this project, $\mathrm{DSR_{UC}}$, can be obtained from the equation (5.5) as:

$$\mathrm{DSR_{UC}} = \frac{\mathrm{DSR_{Cost}}}{\mathrm{DSR_{EAv}}} = £3.35/\mathrm{kWh}$$

E. DSR Incentive Rate

By applying the energy-based DSR mechanism, 80% of DSR cost will be passed onto the customers and the DNO will receive additional DSR incentive which will be annuitized for 15 years, as the estimated lifetime of DSR components.

Given the DNO's rate of return including the weighted average of capital (WACC) of 5.6% and 1% additional rate, and the estimated life time of DSR components of 15 years, the DSR incentive rate can be calculated using equation (5.6) as:

$$\mathrm{DSR_{\ IR}} = \frac{\mathrm{DSR_{UC}} * (1-80\% + \mathrm{WACC} + \mathrm{additional\ rr}) * \mathrm{WACC}}{(1-(1+\mathrm{WACC}))^{-\mathrm{nper}}} = £0.09/\mathrm{kWh}$$

F. Annual DSR Incentive

The annual DSR Incentive for the DNO, which is based on the actual DSR energy participation during winter season in 2012, can be calculated using the equation (5.7) as:

$$\mathrm{DSR_{\ Inc}} = \mathrm{DSR_{\ IR}} * \mathrm{DSR_{EU}} * \mathrm{DSR_{EAc}} = £217.40$$

G. The Maximum Threshold of Energy-Based DSR Incentive

Since the amount of DSR incentive is based on the utilization of the available DSR energy on the system, the maximum threshold of energy-based DSR incentive will be given to the DNO if they can fully utilised the available DSR energy on their system, i.e. DSR energy utilization ($\mathrm{DSR_{EU}}$) is equal to 100%. So, the maximum threshold of energy-based DSR incentive can be calculated using equation (5.8) as:

$$\mathrm{DSR_{IncMax}} = \mathrm{DSR_{\ IR}} * 100\% * \mathrm{DSR_{EAc}} = £6{,}958.10$$

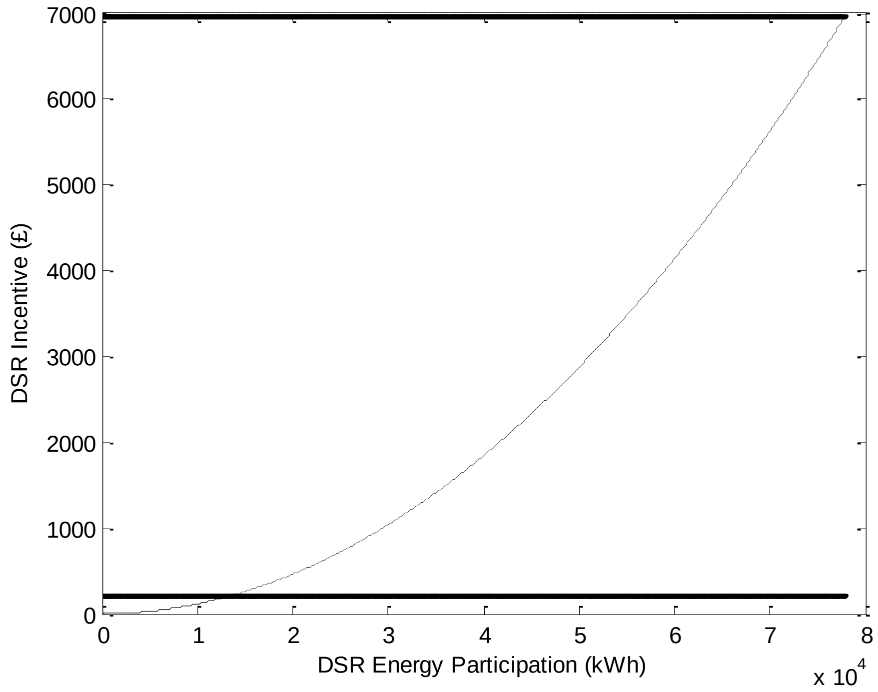

Figure 5.3 The Energy-based DSR Incentive for Case Study 1

As shown in figure 5.3, the energy-based DSR incentive has exponential relation with the DSR energy utilization. Therefore, if the DSR energy utilization is low, the energy-based DSR incentive will be small. As applied in this case study, the DNO can only utilize 17.67% of the available DSR energy of 77,859kWh, they will only receive energy-based DSR incentive as much as £217.4. The maximum threshold of the incentive of £6,958.10 will be given to the DNO if the available DSR energy on the network can be fully utilized, as required.

5.2.2 Case Study 2

The data for the second case study is taken from the Low Carbon London project. This DSR trial project was a series of DSR trials project to examine the effects of energy efficiency schemes and time of use tariffs on industrial and commercial customers.

A. DSR Investment Cost

The Low Carbon London Project is run by another UK's DNO, i.e. the UK Power Networks. The breakdown of project cost is presented in table 5.8.

Cost Category	Sub Cost Category	£ k
Employment Costs	Programme Director	512
	Programme Management Other	310
	Communications & Commercial Managers	468
	Administrative Support	154
	Technical Lead	630
	Network Operations Staff	2,520
	Sub Total	4,594
Equipment Costs	5 ANM schemes	844
	40 aggregator equipment/devices	650
	smart metering	693
	Plugged in Places contribution	1,125
	Substation works	1,328
	Sub Total	4,640
Contractor Costs		-
Customers & Users Payment		2,440
IT Costs	IT costs – operational data store	2,001
	IT costs – Carbon Tool licensing	70
	IT costs – SGS support & software licence	465
	IT costs – Aggregator IT costs	163
	IT costs – comms, infrastructure, environment and interfaces	640
	IT costs – Logica head end	596
	Sub Total	3,835
Other Costs	Contingency	3,247
	Abnormal travel	20
	Public engagement/learning dissemination	1,728
	Inflation	747
	Partner/Collaborator labour costs	7,007
	Other solution/implementation costs	380
	Programme Management Other	1,150
	Sub Total	19,019
Total Costs		29,888

Table 5.8 DSR Costs for Case Study 2 [83]

As seen in table 5.8, the column of contractor costs is blank. This means that all cost categories, in total of £29,888,000.00, are under DNO's responsibility.

B. Available DSR Capacity

For the Low Carbon London project, the details of participants and their available capacity are not provided but the achievement of the DSR trial is provided, as described in section C.

C. DSR Energy Utilization

Since there is no information related to the available DSR capacity in Low Carbon London Project, the calculation of DSR energy utilization for this project is based on the actual energy participation during the trial, which is presented in table 5.9.

Equipment	Number of Events	Participation (MWh)	DSR Period
I&C DSR			1 November 2013 – 28 February 2014
Diesel Generation	24	47.38	
CHP	37	71.66	
Demand Reduction in Building	59	11.08	
Sub Total	120	130.12	
Wind-twinning Trial			
Diesel Generation		36	
CHP		29	
Sub Total	9	65.00	
Total		195.12	

Table 5.9 DSR Energy Participation for Case Study 2 [57]

As seen in table 5.9, the trial was run in the period from 1 November 2013 until 28 February 2014 and was reported successfully done. So, it can be assumed that the DSR participants can fully delivered their energy participation, or in other words, 100% of the available DSR energy which is equal to the actual DSR energy participation, can be utilised during the trial. Hence, the DSR energy utilization for this project is considered equal to 100%.

D. Unit Cost of DSR Incentive

Given the DSR investment cost of £29,888,000.00 and the available DSR energy is assumed to be 195.12MWh, the unit cost of DSR incentive for this project can be obtained from equation (5.5) as:

$$\mathrm{DSR_{UC}} = \frac{\mathrm{DSR_{Cost}}}{\mathrm{DSR_{EAv}}} = £153.18/\mathrm{MWh}$$

E. DSR Incentive Rate

By considering the 80% of pass-through, the DNO's weighted average of capital (WACC) of 5.6% and 1% additional rate, and the estimated life time of DSR components of 15 years, the incentive rate for the Low Carbon London project can be calculated by using equation (5.6) as:

$$\mathrm{DSR_{\,IR}} = \frac{\mathrm{DSR_{UC}} * (1 - 80\% + \mathrm{WACC} + \mathrm{additional\ rr}) * \mathrm{WACC}}{(1 - (1 + \mathrm{WACC}))^{-\mathrm{nper}}} = £4.09/\mathrm{kWh}$$

F. Annual DSR Incentive

Based on the actual DSR energy participation during winter season in 2013, in which the utilization of available DSR energy is equal to 100%, the annual DSR incentive for case study 1 is calculated using equation (5.7) as:

$$\mathrm{DSR}_{\mathrm{Inc}} = \mathrm{DSR}_{\mathrm{IR}} * \mathrm{DSR}_{\mathrm{EU}} * \mathrm{DSR}_{\mathrm{EAc}} = £797{,}316.45$$

G. The Maximum Threshold of Energy-Based DSR Incentive

The maximum threshold of the incentive for case study 2 is equal to the annual DSR energy-based DSR incentive.

$$\mathrm{DSR}_{\mathrm{IncMax}} = \mathrm{DSR}_{\mathrm{IR}} * 100\% * \mathrm{DSR}_{\mathrm{EAc}} = £797{,}316.45$$

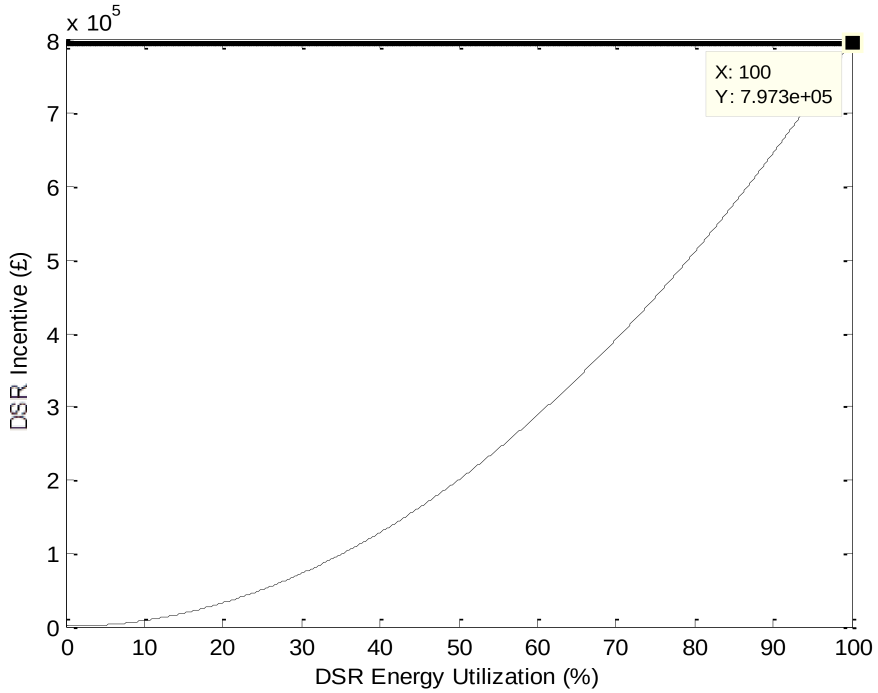

Figure 5.4 The Energy-based DSR Incentive for Case Study 2

Figure 5.4 shows the graph of energy-based DG incentive for case study 2. The energy-based DG incentive will increase exponentially in accordance with the increase of DSR energy utilization. As the available DSR energy is assumed to be fully utilized, the DSR energy utilization is assumed to be equal to 100%. As a result, the DNO will receive the maximum threshold of energy-based DSR incentive of £797,316.45.

5.2.3 Case Study 3

In this case study, the DSR programme will be implemented in the network depicted in figure 3.2. The details of DSR capacity participation and the available DSR energy on the network are given in table 5.10 and 5.11.

A. DSR Capacity Participation

As depicted in figure 5.5, the customers who are connected to the network consist of five industrial/commercial customers and three household groups of customers. The industrial/commercial customers include MD1, MD2, MD3, MD4 and MD5 are connected to the 11kV busbars. While the household customers, including LD1, LD2 and LD3 are connected to the 0.4kV busbars. The details of their participation in DSR programme is presented in table 5.10.

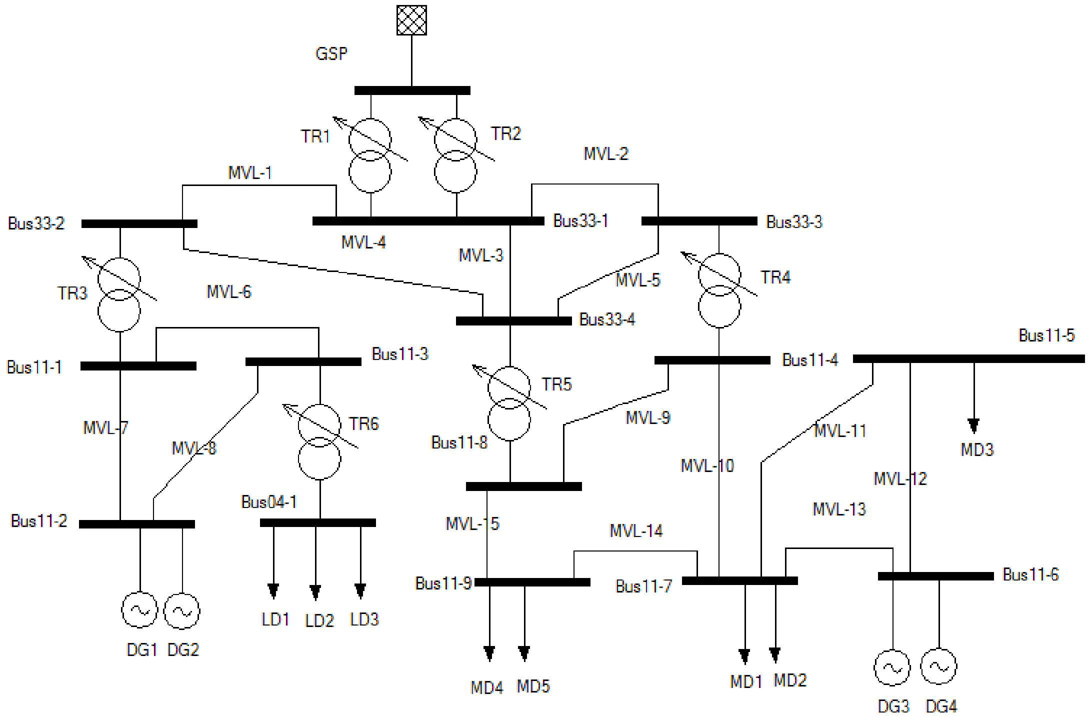

Figure 5.5 The Reference Network for Case Study 3

Name	**Capacity (MW)**	**Type of DSR**	**Participated Capacity (MW)**
MD1 – Industrial/Commercial	4	Demand Reduction	0.3
		On-site Generation	0.2
MD2 – Industrial/Commercial	4	Demand Reduction	0.3
		On-site Generation	0.2
MD3 – Industrial/Commercial	4	Demand Reduction	0.3
		On-site Generation	0.2
MD4 – Industrial/Commercial	3.5	Demand Reduction	0.3
		On-site Generation	0.2
MD5 – Industrial/Commercial	3.5	Demand Reduction	0.3
		On-site Generation	0.2
LD1 – Household Group	1.5	Demand Shifting	0.15
LD2 – Household Group	1.5	Demand Shifting	0.15
LD3 – Household Group	1.5	Demand Shifting	0.15

Table 5.10 The DSR Capacity Participation for Case Study 3

In this scenario, it is assumed that the customers who are participating in demand reduction and on-site generation mechanisms will be called in the events of failure on the network. The participants of demand reduction mechanism will be required to reduce their electricity consumption in the failure caused by a line outage. The total capacity that can be participated in this mechanism is about 1.5MW. For the customers who have installed on-site-generations, they will be required to run their generation in the event of supply scarcity due to a DG is out of service. In total, the on-site generation can contribute 1.0MW of capacity.

In terms of demand shifting mechanism, the participants will be required to shift their electricity consumption from peak times to off-peak times, so that the peak demand can be flattened. Considering the electricity demand profile in the UK, the times of peak demand occur in the period between 5pm and 9pm, during winter and autumn seasons, as depicted in figure 5.6.

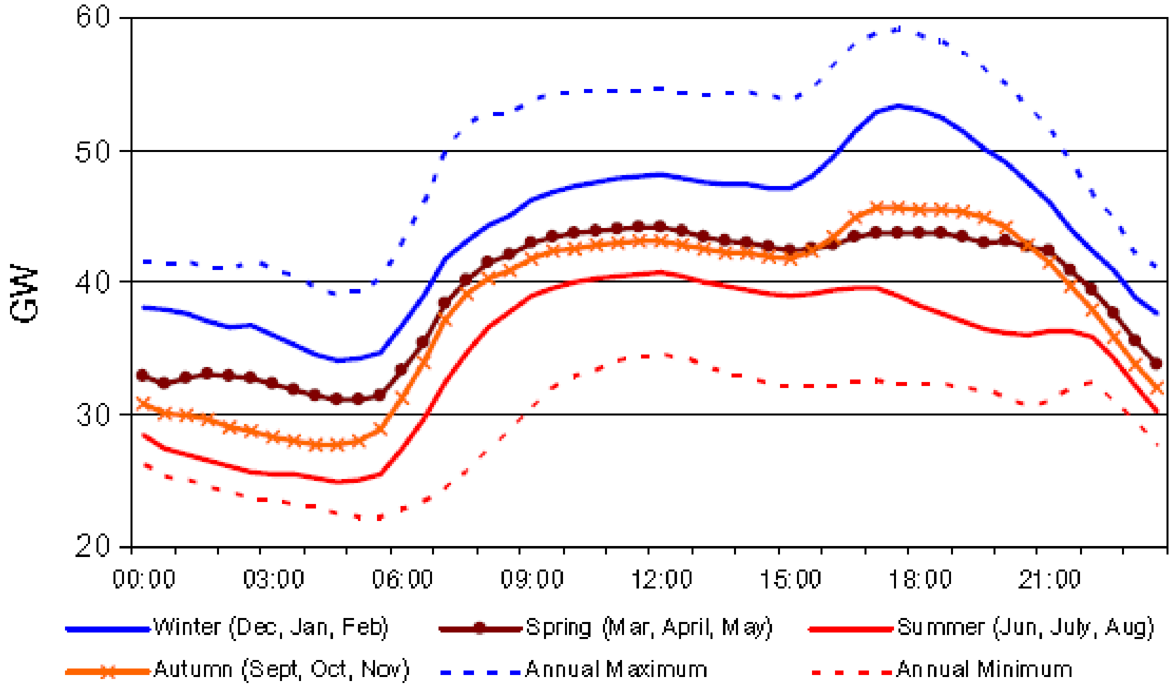

Figure 5.6 Electricity Demand Profile in the UK [86]

In order to determine the available DSR energy participated in DSR programme, some assumptions are taken into account. In one year period, the time duration for demand reduction following a line outage on the network is estimated for 10 hours. The same number is also assumed to be applied for running on-site generation following a DG outage. Regarding the demand shifting, the customers are required to shift their electricity consumption for one hour at times of peak demand during winter and autumn seasons. Since the number of days during winter and autumn seasons is 180 days in total, the duration of DSR participation is equal to 1 x 180 = 180 hours in one year period.

Type of DSR	Participated Capacity (MW)	Duration (hours)	Available DSR Energy (kWh)
Demand Reduction	1.50	10	15,000
On-site Generation	1.00	10	10,000
Demand Shifting	0.45	180	81,000
Total			106,000

Table 5.11 The Available DSR Energy

As presented in table 5.11, the total available DSR energy on the network is around 106,000kWh. From this total energy, 14.5% of it comes from demand reduction participants and 9.5% of it comes from on-site generation participants. Meanwhile, the contribution from demand shifting participants is around 76%.

B. DSR Costs

In this particular example, the costs that must be borne by the DNO including the capital cost and the operational cost. The breakdown of the required investment cost is presented in table 5.12.

Cost Category	Per Site (£)	Units	Total (£)
Capital Cost	35,000.00	8	280,000.00
Operational Cost	5% of total capital cost		14,000.00
Total			294,000.00

Table 5.12 DSR Investment Cost for Case Study 3

As shown in table 5.12, the required capital cost is estimated to be £35,000.00 per site and the required operational cost to implement DSR programme on the network is estimated as 5% from the total capital cost [85]. So, in total, the required investment cost is estimated to be £294,000.00.

C. DSR Energy Utilization

By assuming that the available DSR energy can be fully utilized during one year period, the DSR energy utilization will be equal to 100%.

$$\mathrm{DSR_{EU}} = \frac{\mathrm{DSR_{EAc}}}{\mathrm{DSR_{EAv}}} = 100\%$$

D. Unit Cost of DSR Incentive Rate

Given the total DSR cost of £294,000 and total available DSR energy of 106,000 kWh, the unit cost of energy-based DSR incentive is calculated using equation (5.5) as:

$$\mathrm{DSR_{UC}} = \frac{\sum \mathrm{DSR_{Cost}}}{\mathrm{DSR_{EAv}}} = £2.77/\mathrm{kWh}$$

E. Energy-Based DSR Incentive Rate

By considering the WACC of 5.6% and additional 1% rate of return and the lifetime of DG connection assets of 15 years, the incentive rate can be obtained from equation (5.6) as:

$$\mathrm{DSR_{IR}} = \frac{\mathrm{DSR_{UC}} * (1-80\% + \mathrm{WACC} + \mathrm{additional\ rr}) * \mathrm{WACC}}{(1-(1+\mathrm{WACC}))^{-\mathrm{nper}}} = £0.07/\mathrm{kWh}$$

F. Annual Energy-Based DSR Incentive

Given the actual DSR energy of 106,000 kWh, which is equal to 100% of DSR energy utilization, and the incentive rate of £0.07/kWh, the annual energy-based DSR incentive for the DNO can be calculated using equation (5.7) as:

$$\mathrm{DSR}_{\mathrm{Inc}} = \mathrm{DSR}_{\mathrm{IR}} * \mathrm{DSR_{EU}} * \mathrm{DSR_{EAc}} = £7{,}842.98$$

G. Maximum Threshold of Energy-Based DSR Incentive

The maximum threshold of the incentive for this study is equal to the annual DSR energy-based DSR incentive.

$$\mathrm{DSR_{IncMax}} = \mathrm{DSR}_{\mathrm{IR}} * 100\% * \mathrm{DSR_{EAc}} = £7{,}842.98$$

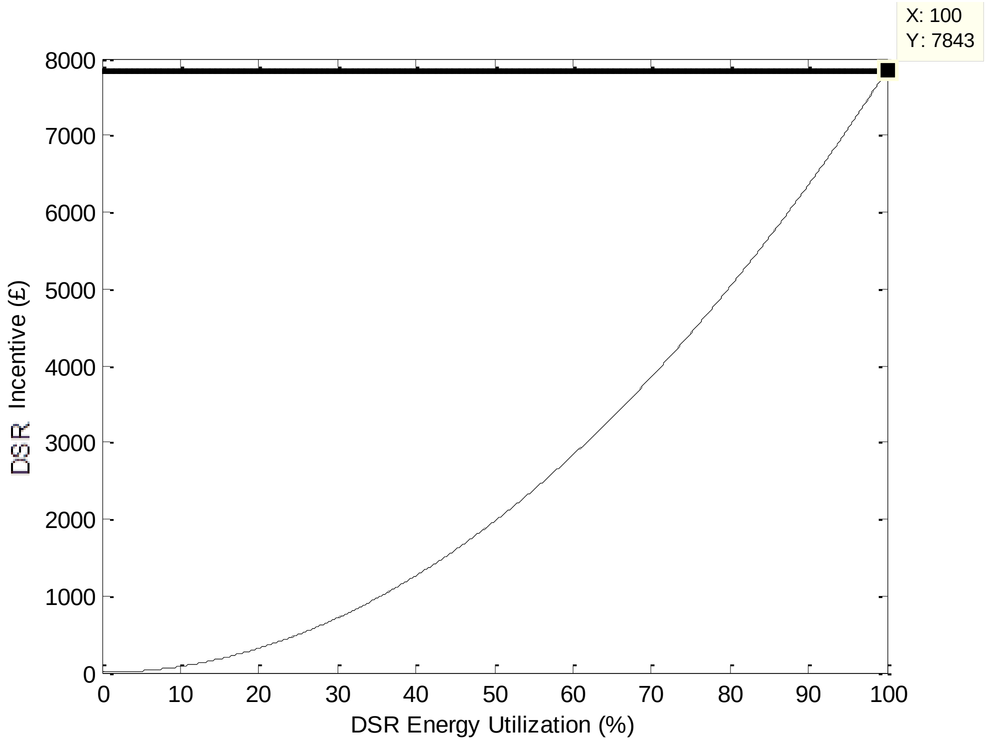

Figure 5.7 Energy-based DSR Incentive for Case Study 3

Figure 5.7 shows the graph of energy-based DSR incentive for case study 3. The energy-based DSR incentive will increase exponentially in accordance with the increase of DSR energy utilization. As the available DSR energy is assumed to be fully utilized, the DSR energy utilization is assumed to be equal to 100%. As a result, the DNO will receive the maximum threshold of energy-based DSR incentive of £7,842.98.

5.3 COMPARISON BETWEEN ENERGY-BASED DSR INCENTIVE AND CURRENT MECHANISMS

Based on the explanation of current DSR incentive mechanism in chapter 2, the comparison between the proposed mechanism, i.e. energy-based DSR incentive mechanism, and current mechanisms can be seen in table 5.13.

DSR Incentive Mechanism	Implementation
Demand Management Incentive Mechanism	Allowing DNOs to recover the costs and forgone revenues associated with DSR initiatives through higher electricity prices
Rate of Return Mechanism	Allowing DNOs to earn profit on DSR investment, based on the utility's rate base, in the same manner as other capital investments
Shared Savings Mechanism	Giving DNOs a percentage share of the energy saving as a result of DSR programme
Avoided Cost Mechanism	Giving DNOs a percentage of their avoided supply costs as their DSR compensation
Low Carbon Network Fund	Giving financial support to DNOs for DSR trials or initiatives on their network
Energy-based DSR Incentive Mechanism	Allowing DNOs to receive additional incentive based on the utilization of available DSR energy and its relation with the required investment cost

Table 5.13 Comparison between Energy-based DSR Incentive and Current Mechanisms

5.4 CHAPTER SUMMARY

The implementation of proposed energy-based DG incentive mechanism on case study 1, 2 and 3 can be summarized as follows:

	Case Study 1	Case Study 2	Case Study 3
Investment Cost (£)	260,900.00	29,888,000.00	294,000.00
Available DSR Energy (kWh)	77,859.60	195,120.00	106,000.00
Actual DSR Energy Participation (kWh)	13,759.20	195,120.00	106,000.00
DSR Energy Utilization (%)	17.67	100.00	100.00
Unit Cost of Energy-based DSR Incentive (£/kWh)	3.35	153.18	2.77
Energy-based DSR Incentive Rate (£/kWh)	0.09	4.09	0.07
Annual Energy-based DSR Incentive (£)	217.4	797,316.45	7,842.98
Maximum Threshold of Energy-based DSR Incentive (£)	6,958.10	797,316.45	7,842.98

Table 5.14 Energy-based DSR Incentive Mechanism for Case Study 1, 2 and 3

As presented in table 5.14, the incentive for DNOs associated with DSR implementation on their distribution networks depends on the utilization of available DSR energy on the network and its relation with the required investment cost. The higher the DSR energy utilization, the higher the incentive for the DNOs.

Comparing with current incentive mechanism, energy-based DSR incentive can reflect the effectiveness of DNOs to deal with the required investments in association with DSR implementation on their network.

6 MIXED INCENTIVES FOR DISTRIBUTION NETWORK OPERATORS

In association with the deployment of distributed generation (DG) and the implementation of demand side response (DSR) programme on electricity distribution networks, the role of Distribution network operators (DNOs) is vital because they are responsible in operating, maintaining and developing the distribution networks.

Currently DNOs do not have huge experience in connecting large amount of DG as well as deploying DSR programmes on their network. In order to encourage DNOs to be more active in the development of DGs and DSR programmes, financial incentives for DNOs related to those activities are required.

The proposed energy-based DG incentive mechanism, which is described in chapter 4, aims to incentivise DNOs in providing DG connection on their network. The incentive is calculated based on the utilization of DG energy available on the network and its relation with the requirement of network reinforcement. This mechanism can reflect the effectiveness of DNOs to deal with the required investment associated with DG connection.

Meanwhile, the proposed energy-based DSR incentive, which is described in chapter 5, aims to incentivise DNOs associated with DSR initiatives. This mechanism allows DNOs to receive incentive based on the utilization of DSR energy available and its relation with the required investment cost. Therefore, it can reflect the effectiveness of DNOs in their investment related to the implementation of DSR programme on their network.

In order to find out more about the proposed mechanisms and the relation between them, this chapter describes the assessment of the impact of connecting DG and implementing DSR programme on the same network to the amount of incentives for the DNOs.

6.1 IMPLEMENTATION OF MIXED ENERGY-BASED DG AND DSR INCENTIVES

6.1.1 Principles of the Mixed Energy-based DG and DSR Incentives

Basically, the mixed energy-based DG and DSR Incentives mechanism combines the two incentive mechanisms, i.e. energy-based DG incentive and energy-based DSR incentive mechanisms. The DNOs will be incentivised for their investment in providing DG connection and implementing DSR programmes on their distribution networks.

The energy-based DG incentive is calculated based on the utilization of DG energy available on the network in association with the network reinforcement cost. Meanwhile, energy-based DSR incentive will be given in accordance with the utilization of DSR energy participation by considering the required investment cost.

The mixed energy-based DG and DSR incentives consider the interaction between connecting DG and implementing DSR programme on the same distribution network. The participation of customers in DSR programme, especially in demand reduction and running on-site generations mechanisms, is related to the single outage (N-1) contingency. When an outage occurs, the customers will be asked to reduce their energy consumption and to operate their on-site generation to deal with the outage. In case where the connection of a new DG requires the network to be reinforced, the functionality of DSR programme on that particular network will be affected. After the network has been reinforced, the single outage (N-1) contingency might not interrupt the operation of the network, so that, the customers are not required to participate in one of DSR mechanisms. This indicates that the DNOs do not necessarily need to invest in DSR programme on that particular network but they might be still required to implement DSR programme on other parts of the network.

Therefore, by implementing mixed energy-based DG and DSR incentives mechanism, the DNOs are expected to be more effective on their investment in accommodating DG connection and implementing DSR programme on their network.

6.1.2 Structure of the Incentive Mechanism

The mixed energy-based DG and DSR incentives mechanism also adopts the hybrid mechanism, i.e. by giving a partial pass-through mechanism and additional incentive rate. Pass-through mechanism allows DNOs to pass 80% of their investment cost on to the customers. Then, they will receive additional 20% incentive rate which will be annuitized for a particular period of time, by considering the rate of return of the investment cost and the life time of the reinforced components.

6.1.3 Methodology to Develop Mixed Energy-based DG and DSR Incentives

Mixed energy-based DG and DSR incentive mechanism is developed based on the combination of methodologies used in both DG and DSR incentive mechanisms, which will be explained further in the case study.

6.2 CASE STUDY

For the purpose of investigating of the impact of connecting DG and implementing DSR programme, the assessment is conducted by using the same reference network which is used in the previous chapters.

6.2.1 Load Flow Analysis of the Reference Network

The connection of DG and the implementation of DSR on the distribution network will impact on the network performance, including voltage level, network capacity utilization and power losses. Amongst these three parameters, the level of network capacity utilization will determine whether a particular network component needs to be upgraded or not. If the network capacity utilization is more than 100%, which means that the capacity standard of the component is exceeded, network reinforcement is required. Therefore, in this case study, the analysis will focus on the power flow on each branch/line.

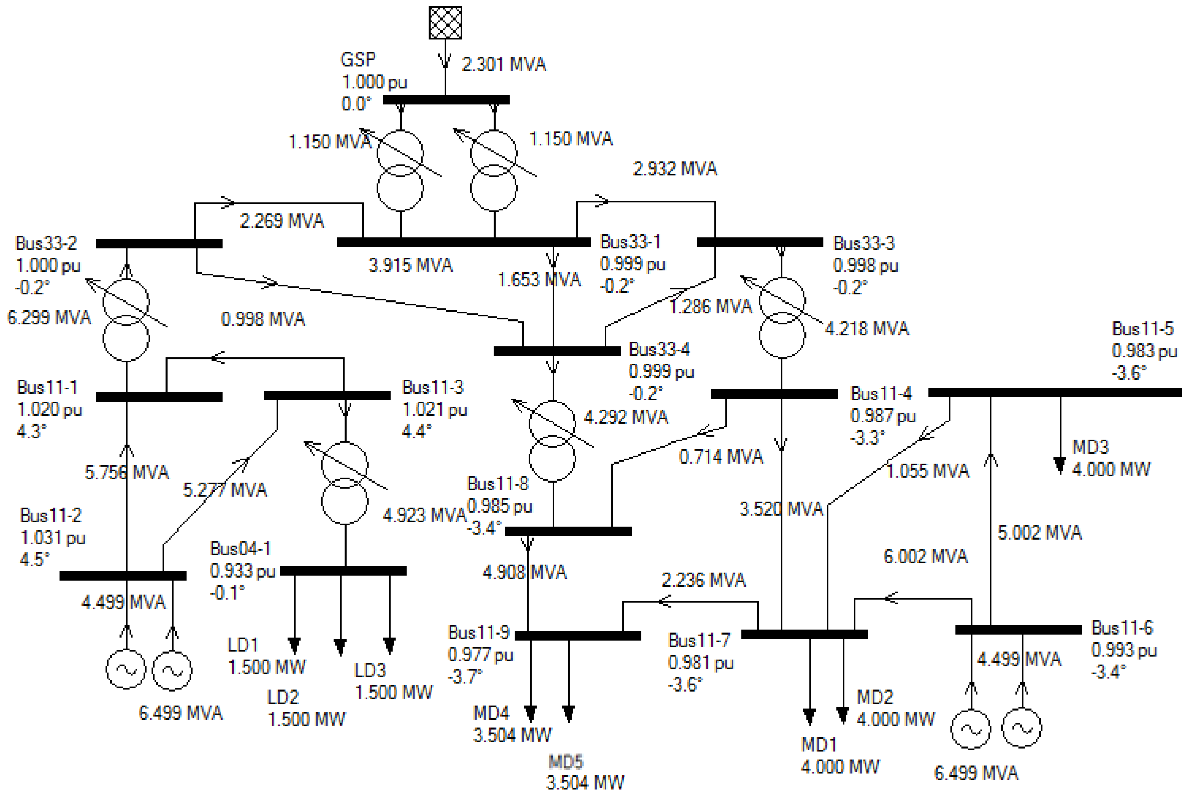

Figure 6.1 Load Flow Analysis of the Reference Network

Figure 6.1 depicts the load flow analysis results of the reference network. The figure shows the voltage level of each busbar, expressed in (pu) and the voltage angle. The connected capacity of each DG is expressed in (MVA) and the demand is expressed in (MW). While the power flow, is expressed in (MVA). The details of the power flow on each branch/line are presented in table 6.1.

From Busbar	To Busbar	Rating	Power Flow (MVA)	Network Capacity Utilization (%)
GSP	Bus33-1	40.000	1.150	3%
GSP	Bus33-1	40.000	1.150	3%
Bus33-2	Bus33-1	15.433	2.269	15%
Bus33-2	Bus11-1	10.000	6.299	63%
Bus11-1	Bus11-2	7.049	5.756	82%
Bus11-1	Bus11-3	7.049	998	14%
Bus11-3	Bus04-1	7.500	4.923	66%
Bus33-4	Bus11-8	10.000	4.292	43%
Bus11-8	Bus11-9	7.049	4.908	70%
Bus33-1	Bus33-4	15.433	1.653	11%
Bus33-1	Bus33-3	15.433	2.932	19%
Bus33-3	Bus11-4	10.000	4.218	42%
Bus11-3	Bus11-2	7.049	5.277	75%
Bus11-4	Bus11-8	7.049	714	10%
Bus33-3	Bus33-4	15.433	1.286	8%
Bus33-2	Bus33-4	15.433	3.915	25%
Bus11-5	Bus11-7	7.049	1.055	15%
Bus11-9	Bus11-7	7.049	2.236	32%
Bus11-4	Bus11-7	7.049	3.520	50%
Bus11-7	Bus11-6	7.049	6.002	85%
Bus11-5	Bus11-6	7.049	5.002	71%

Table 6.1 Load Flow Analysis for the Reference Network

6.2.2 Assessment of Single Outage (N-1) Contingency Criterion

Single outage (N-1) contingency criterion means that the network should continue to operate following a failure of a network component [89]. This can be caused by one of the lines, transformers, or a generation unit is out of service.

The (N-1) criterion for the reference network will be examined by disconnecting one of the lines on the network, including the line between Bus11-4 and Bus11-7, the line between Bus11-7 and Bus11-9, and the line between Bus11-8 and Bus11-9. The assessment of (N-1) contingency is also carried out by disconnecting DG3 from Bus11-6. The result of load flow analysis for the (N-1) contingency of the reference network can be seen in table 6.2.

From Busbar	To Busbar	Rating	Network Capacity Utilization							
			B114-B117 Outage		B117-B119 Outage		B118-B119 Outage		DG3 Outage	
		(MVA)	(MVA)	(%)	(MVA)	(MVA)	(%)	(MVA)	(MVA)	(%)
GSP	Bus33-1	40.000	1.200	3%	1.170	3%	1.248	3%	4.709	12%
GSP	Bus33-1	40.000	1.200	3%	1.170	3%	1.248	3%	4.709	12%
Bus33-2	Bus33-1	15.433	2.225	14%	2.253	15%	2.267	15%	1.195	8%
Bus33-2	Bus11-1	10.000	6.299	63%	6.299	63%	6.298	63%	6.293	63%
Bus11-1	Bus11-2	7.049	5.756	82%	5.756	82%	5.756	82%	5.754	82%
Bus11-1	Bus11-3	7.049	0.998	14%	0.998	14%	0.999	14%	1.001	14%
Bus11-3	Bus04-1	7.500	4.923	66%	4.923	66%	4.924	66%	4.931	66%
Bus33-4	Bus11-8	10.000	4.567	46%	4.395	44%	4.117	41%	7.696	77%
Bus11-8	Bus11-9	7.049	8.467	120%	7.100	101%			7.322	104%
Bus33-1	Bus33-4	15.433	1.747	11%	1.689	11%	1.657	11%	4.261	28%
Bus33-1	Bus33-3	15.433	2.893	19%	2.920	19%	3.120	20%	5.959	39%
Bus33-3	Bus11-4	10.000	4.051	41%	4.163	42%	4.591	46%	7.676	77%
Bus11-3	Bus11-2	7.049	5.277	75%	5.277	75%	5.277	75%	5.280	75%
Bus11-4	Bus11-8	7.049	4.011	57%	2.870	41%	4.073	58%	0.102	1%
Bus33-3	Bus33-4	15.433	1.161	8%	1.245	8%	1.473	10%	1.725	11%
Bus33-2	Bus33-4	15.433	3.960	26%	3.931	25%	3.916	25%	5.167	33%
Bus11-5	Bus11-7	7.049	1.054	15%	1.056	15%	1.054	15%	1.205	17%
Bus11-9	Bus11-7	7.049	1.883	27%			7.103	101%	0.307	4%
Bus11-4	Bus11-7	7.049			1.883	27%	8.554	121%	7.464	106%
Bus11-7	Bus11-6	7.049	6.002	85%	6.002	85%	6.002	85%	1.682	24%
Bus11-5	Bus11-6	7.049	5.002	71%	5.001	71%	5.002	71%	2.833	40%

Table 6.2 Load Flow Analyses for (N-1) Contingency of the Reference Network

Table 6.2 shows the analysis results for the (N-1) contingency of the reference network due to one of the outages presented in the table. These outages will cause the power flow of particular lines to exceed the standard capacity, indicated by the network capacity utilization is more than 100%.

As presented in table 6.2, the outage of the line between Bus11-4 and Bus11-7 will cause the network capacity utilization of the line between Bus11-8 and Bus11-9 to reach 120%. The capacity standard of the same line will also be exceeded because of the outage of the line between Bus11-7 and Bus11-9, indicated by its network capacity utilization of 101%.

The impact of (N-1) contingency of the reference network can also be explained by referring to the network depicted in figure 6.2. The network depicts the load flow analysis result of the reference network due to the outage of the line between Bus11-8 and Bus11-9.

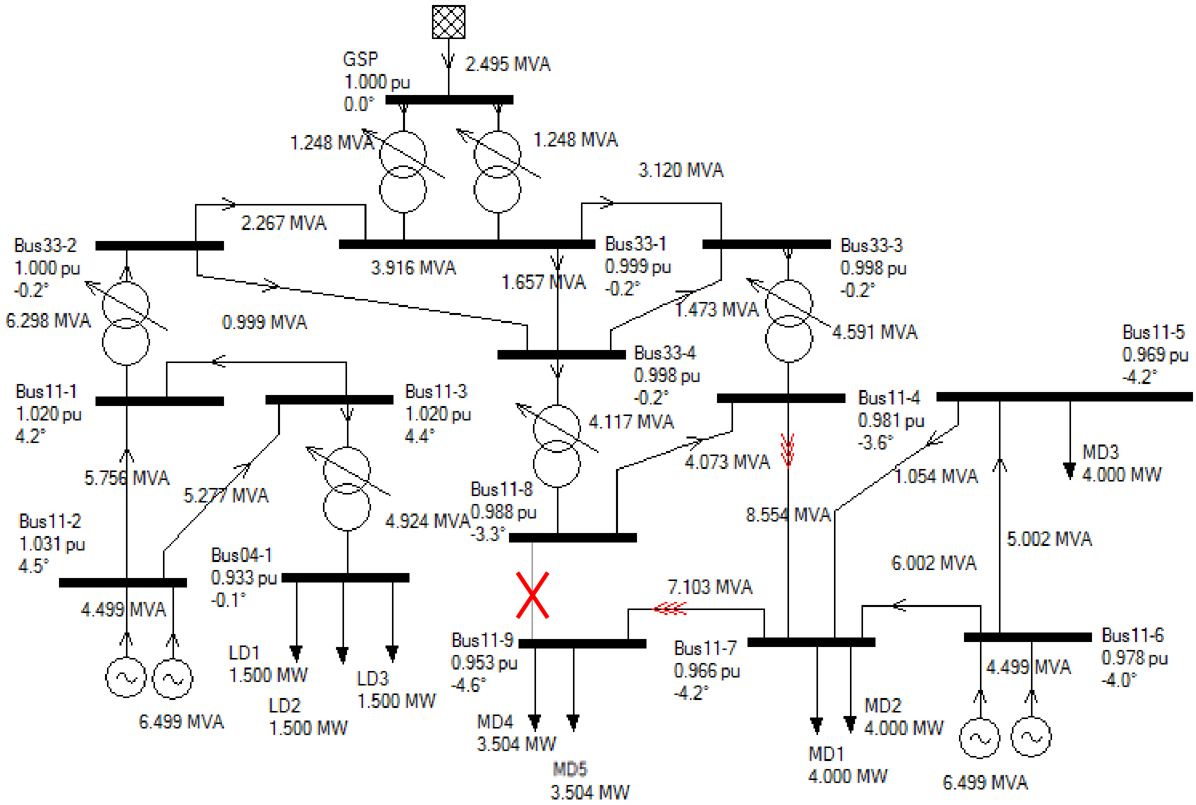

Figure 6.2 Load Flow Analysis of (N-1) Contingency Caused by a Line Outage

As shown in figure 6.2, if the line between Bus11-8 and Bus11-9 is out of service, the power flow of the line between Bus11-4 and Bus11-7, of 8.554MVA, and the power of the line between Bus11-7 and Bus11-9, of 7.103MVA, are higher than their capacity standard of 7.049MVA. The triple arrows on those lines indicate that the network capacity utilization of the lines are more than 100%. The increase of the power flow of those lines is caused by the power, which is previously distributed through the line between Bus11-8 and Bus11-9, will flow through other lines to supply the demand. As a result, it will increase the initial power flow on those lines.

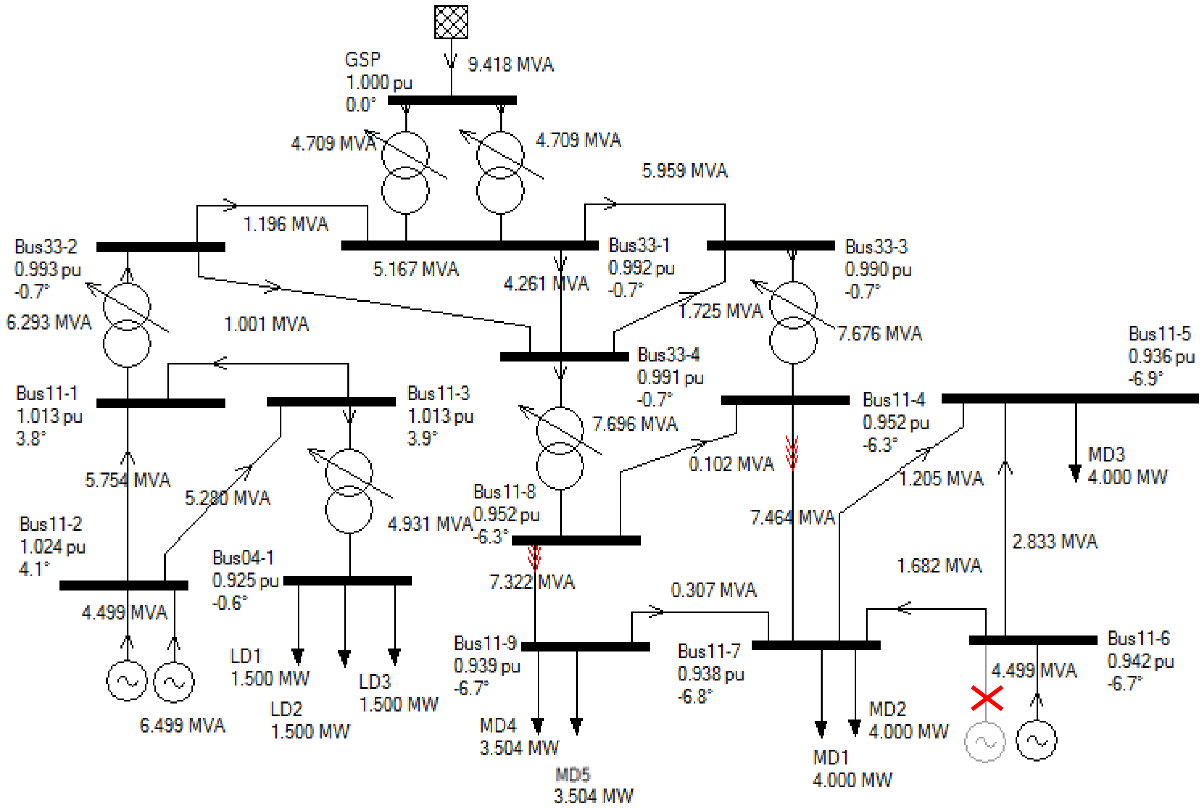

Figure 6.3 Load Flow Analysis of (N-1) Contingency Caused by a DG Outage

Figure 6.3 depicts the impact of a DG3 outage which is previously connected to Bus11-6. This outage causes the power flow of particular lines to increase exceeding their capacity standard. The power flow of line between Bus11-4 and Bus11-7 reaches 7.464MVA which is equal to 106% of the capacity standard, the power flow of line between Bus11-8 and Bus11-9 reaches 7.322MVA which is equal to 104% of the capacity standard.

The outage of DG3 means that the power which is previously generated by DG 3 to supply demand connected to Bus11-7 and Bus11-9 is cut. Therefore, those demands will be supplied by the power from network which is flowing through the line between Bus11-4 and Bus11-7, and through the line between Bus11-8 and Bus11-9. Because of this additional power, the power flow on those lines increases.

6.2.3 Implementing DSR to Deal with the Single Outage (N-1) Contingency

The single outage (N-1) contingencies, including line and DG outages might cause the network capacity of particular lines to exceed 100%. In order to deal with this problem, DSR mechanisms, including demand reduction and running on-site generation can be applied.

Demand reduction mechanism aims to reduce the electricity demand, so that, the power flow on the related lines will decrease. While running on-site generation mechanism aims to generate electricity at customers' side to supply their demand, so that, it will decrease the power imported from the network. Moreover, the excess power from the on-site generation can be exported to the network. As a result, this will decrease the network utilization of the related lines.

1). DSR Capacity Participation

As depicted in figure 6.3, the customers who are connected to the network consist of eight groups of customers include MD1, MD2, MD3, MD4, MD5, LD1, LD2 and LD3. The letters MD means that the customers are connected to the medium voltage of 11kV, while LD indicates the low voltage of 0.4kV. In this case, the participation of each customer group in DSR programme is assumed to be as presented in table 6.3.

Name	Capacity (MW)	Type of DSR	Participated Capacity (MW)
MD1 – Industrial/Commercial	4	Demand Reduction	0.3
		On-site Generation	0.2
MD2 – Industrial/Commercial	4	Demand Reduction	0.3
		On-site Generation	0.2
MD3 – Industrial/Commercial	4	Demand Reduction	0.3
		On-site Generation	0.2
MD4 – Industrial/Commercial	3.5	Demand Reduction	0.3
		On-site Generation	0.2
MD5 – Industrial/Commercial	3.5	Demand Reduction	0.3
		On-site Generation	0.2
LD1 – Household Group	1.5	Demand Shifting	0.15
LD2 – Household Group	1.5	Demand Shifting	0.15
LD3 – Household Group	1.5	Demand Shifting	0.15

Table 6.3 The DSR Capacity Participation for Case Study 3

In the event of failure, the customers who are participating in demand reduction will be required to reduce their electricity consumption, while the customers who have installed on-site-generations will be required to run their generation. As seen in table 6.3, the total participated capacity in demand reduction mechanism is around 1.5MW and the total participation of on-site generation is estimated at 1.0MW.

Meanwhile, the customers who participate in demand shifting mechanism are required to shift their energy consumption at peak demand times to off-peak demand times, for the period of one hour during winter and autumn seasons.

2). Impact of DSR Implementation on Single Outage (N-1) Contingency

Table 6.4 presents the results of load flow analysis for the implementation of DSR mechanisms on (N-1) contingency. The DSR mechanisms, including demand reduction and running on-site generation are applied following one of the outages presented in the table.

From Busbar	**To Busbar**	**Rating**	**Network Capacity Utilization**							
			DSR Following B114-B117 Outage		**DSR Following B117-B119 Outage**		**DSR Following B118-B119 Outage**		**DSR Following DG3 Outage**	
		(MVA)	**(MVA)**	**(%)**	**(MVA)**	**(%)**	**(MVA)**	**(%)**	**(MVA)**	**(%)**
GSP	Bus33-1	40.000	351	1%	351	1%	320	1%	3.274	8%
GSP	Bus33-1	40.000	351	1%	351	1%	320	1%	3.274	8%
Bus33-2	Bus33-1	15.433	2719	18%	2.727	18%	2.754	18%	1.579	10%
Bus33-2	Bus11-1	10.000	6300	63%	6.300	63%	6.300	63%	6.295	63%
Bus11-1	Bus11-2	7.049	5757	82%	5.757	82%	5.757	82%	5.755	82%
Bus11-1	Bus11-3	7.049	998	14%	998	14%	998	14%	1.000	14%
Bus11-3	Bus04-1	7.500	4921	66%	4.921	66%	4.921	66%	4.928	66%
Bus33-4	Bus11-8	10.000	3207	32%	3.134	31%	2.889	29%	6.310	63%
Bus11-8	Bus11-9	7.049	5999	85%	6.069	86%			6.107	87%
Bus33-1	Bus33-4	15.433	782	5%	759	5%	732	5%	3.209	21%
Bus33-1	Bus33-3	15.433	1810	12%	1.843	12%	1.959	13%	4.740	31%
Bus33-3	Bus11-4	10.000	2843	28%	2.928	29%	3.219	32%	6.289	63%
Bus11-3	Bus11-2	7.049	5277	75%	5.277	75%	5.277	75%	5.279	75%
Bus11-4	Bus11-8	7.049	2835	40%	3.078	44%	2.878	41%	74	1%
Bus33-3	Bus33-4	15.433	1036	7%	1.087	7%	1.268	8%	1.554	10%
Bus33-2	Bus33-4	15.433	3471	22%	3.462	22%	3.437	22%	4.660	30%
Bus11-5	Bus11-7	7.049	1361	19%	1.363	19%	1.361	19%	885	13%
Bus11-9	Bus11-7	7.049	1544	22%			6.070	86%	242	3%
Bus11-4	Bus11-7	7.049			1.548	22%	6.056	86%	6.131	87%
Bus11-7	Bus11-6	7.049	6168	88%	6.168	88%	6.168	88%	1.845	26%
Bus11-5	Bus11-6	7.049	4835	69%	4.835	69%	4.835	69%	2.667	38%

Table 6.4 Load Flow Analyses after DSR Implementation

As presented in table 6.4, the implementation of DSR mechanism following an outage can reduce the network capacity utilization, less than 100%. This due to demand reduction mechanism can reduce the power consumed by demand, so that the power flow on the network will decrease. Meanwhile, on-site generation can generate power to supply near-by demand. As the demand has been partly supplied by on-site generation, the amount of imported power can be reduced, as a result, the power flow on the related lines will decrease. As the power flow decrease, the network capacity utilization will decrease as well.

For instance, the outage of the line between Bus11-4 and Bus117 will cause the network capacity utilization of the line between Bus11-8 and Bus11-9 reaches 120%. After demand reduction and running on-site generation mechanisms are applied, the network capacity utilization of the line decreases by 35%. While the implementation of these DSR mechanisms following the outage of the line between Bus117 and Bus11-9 will decrease the network capacity utilization of the line between Bus11-8 and Bus11-9 from 101% down to 86%.

The impact of DSR mechanisms, which is applied following the outage of the line between Bus11-8 and Bus 11-9, can be explained by using figure 6.4.

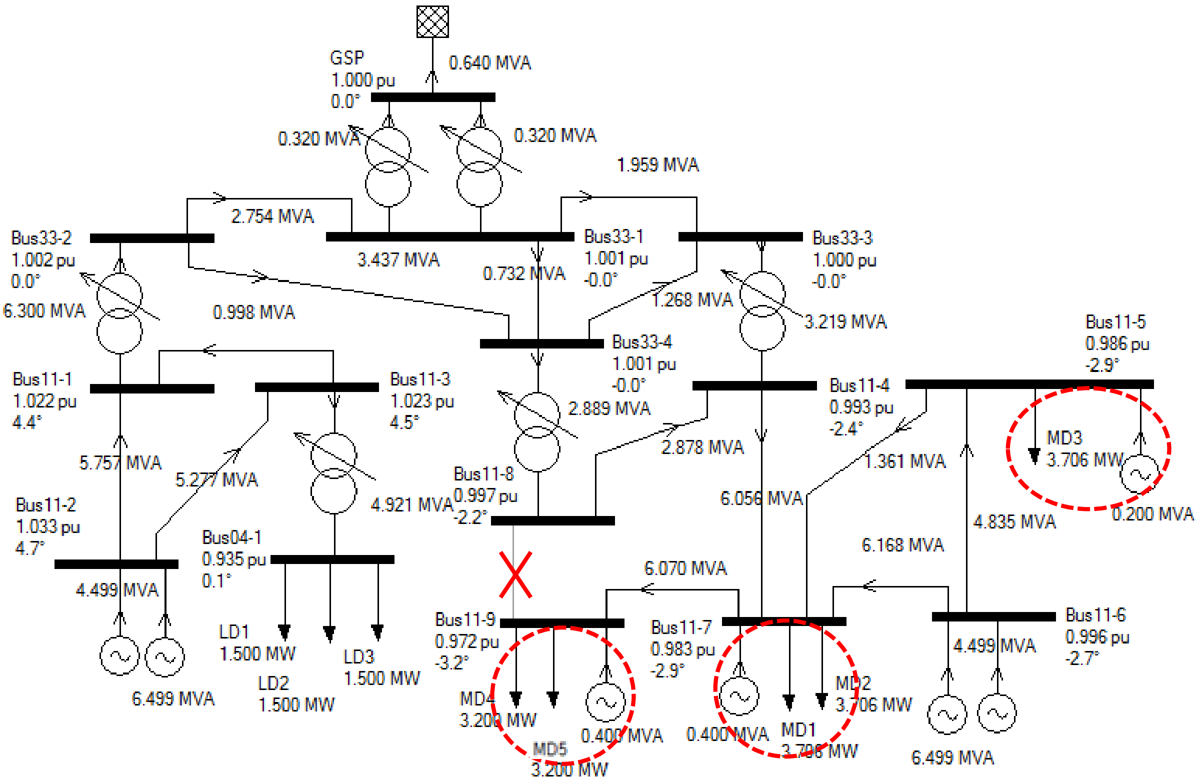

Figure 6.4 Load Flow Analyses for DSR Implementation Following a Line Outage

Following the outage of the line between Bus11-8 and Bus11-9, the network utilization of the line between Bus11-4 and Bus11-7 and the network utilization of the line between Bus11-7 and Bus11-9 will reach 101% and 121%, respectively. By applying demand reduction and on-site generation mechanisms, as depicted in figure 6.4, the power flow on those lines can be reduced down to 6.070MVA and 6.056MVA, which are equal to the reduction of network capacity utilization of those lines by 15% and 35%, respectively.

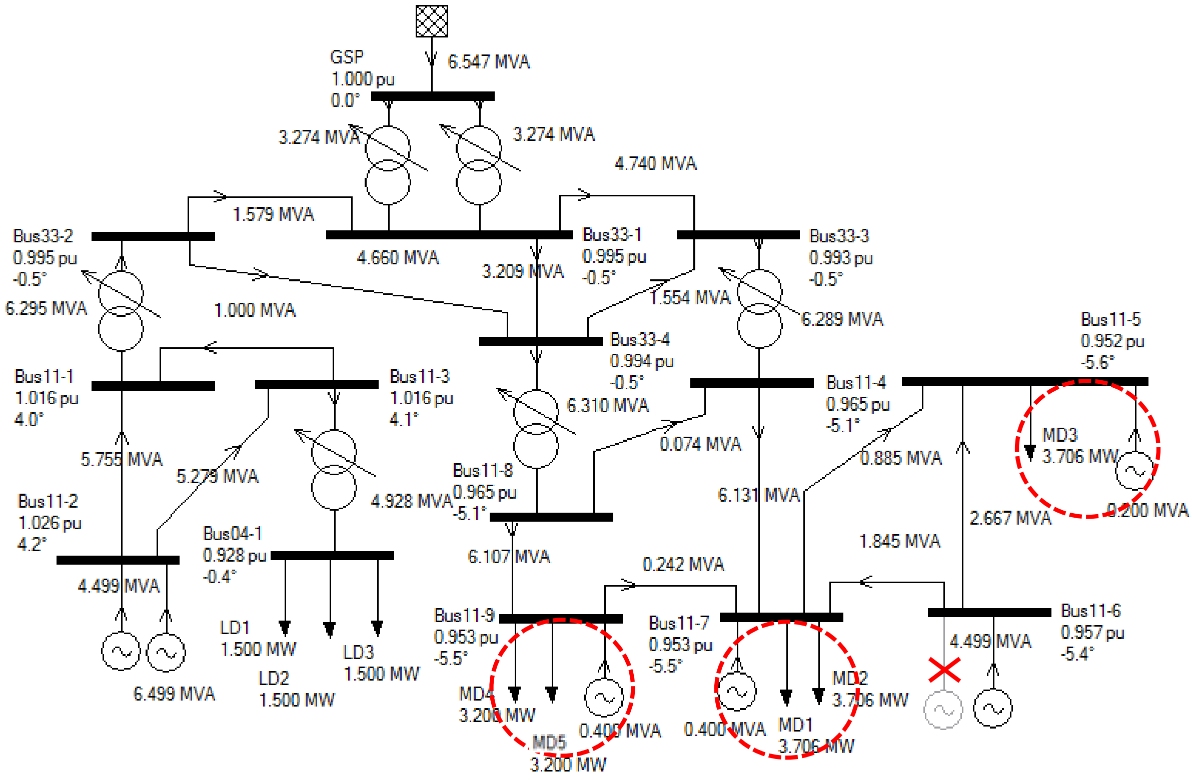

Figure 6.5 Load Flow Analyses for DSR Implementation Following a DG Outage

Figure 6.5 shows the impact of reducing demand and running on-site generation on the power flow of the related lines. Following the outage of the DG3 which is previously connected to Bus11-6, the network utilization of the line between Bus11-4 and Bus11-7 and the network utilization of the line between Bus11-8 and Bus11-9 will increase up to 106% and 104%, respectively. Then, by applying demand reduction and on-site generation mechanisms, the power flow on those lines can be reduced down to 6.131MVA and 6.107MVA, which are equal to the reduction of network capacity utilization of those lines by 19% and 17%, respectively.

6.2.4 Implementation of Energy-based DSR Incentive

The energy-based DSR incentive is developed in association with the implementation of DSR programme on the distribution network.

A. Available DSR Energy

In this case, it is assumed that the period of customers' participation both in demand reduction and on-site generation mechanisms will be for two and a half hours during the event of failure. There are four failures examined in this case, including the outage of the line between Bus11-4 and Bus11-7, the outage of the line between Bus11-7 and Bus11-9, the outage of the line between Bus11-8 and Bus11-9, and the outage of DG3 which is connected to Bus11-6. It is also assumed that each outage might happen once in a year.

In terms of demand shifting mechanism, the customers are required to shift their energy consumption from peak demand times to off-peak demand times for one hour period, during winter and autumn seasons. Since the number of days during winter and autumn seasons is 180 days in total, the duration of DSR participation is equal to 1 x 180 = 180 hours in one year period. Hence, the total the total available DSR energy on the network is around 106,000kWh, as presented in table 6.5.

(N-1) Contingency	DSR Mechanisms	Participated Capacity (MW)	Duration (hours)	Available DSR Energy (kWh)
The line between Bus11-4 and Bus11-7 is out of service	Demand Reduction	1.50	2.5	3,750
	On-site Generation	1.00	2.5	2,500
The line between Bus11-4 and Bus11-7 is out of service	Demand Reduction	1.50	2.5	3,750
	On-site Generation	1.00	2.5	2,500
The line between Bus11-4 and Bus11-7 is out of service	Demand Reduction	1.50	2.5	3,750
	On-site Generation	1.00	2.5	2,500
DG3 is out of service	Demand Reduction	1.50	2.5	3,750
	On-site Generation	1.00	2.5	2,500
Demand Shifting		0.45	180.0	81,000
Total				106,000

Table 6.5 The Available DSR Energy

B. DSR Costs

The costs that must be borne by the DNO in implementing DSR programme include the capital cost and the operational cost. The breakdown of the required investment cost is given in table 6.6.

Cost Category	Per Site (£)	Units	Total (£)
Capital Cost	35,000.00	8	280,000.00
Operational Cost	5% of total capital cost		14,000.00
Total			294,000.00

Table 6.6 DSR Investment Cost for Case Study 4

As presented in table 6.6, the required capital cost is estimated to be £35,000.00 per site and the required operational cost to implement DSR programme on the network is estimated as

5% from the total capital cost [85]. So, in total, the required investment cost is estimated to be £294,000.00

D. Unit Cost of DSR Incentive Rate

Given the total DSR cost of £294,000 and total available DSR energy of 106,000 kWh, the unit cost of energy-based DSR incentive is obtained as:

$$\mathrm{DSR_{UC}} = \frac{\sum \mathrm{DSR_{Cost}}}{\mathrm{DSR_{EAv}}} = £2.77/\mathrm{kWh}$$

E. Energy-Based DSR Incentive Rate

By considering the WACC of 5.6% and additional 1% rate of return and the lifetime of DG connection assets of 15 years, the incentive rate can be obtained from equation (5.6) as:

$$\mathrm{DSR_{IR}} \quad = \frac{\mathrm{DSR_{UC}} * (1-80\% + \mathrm{WACC} + \mathrm{additional\ rr}) * \mathrm{WACC}}{(1-(1+\mathrm{WACC}))^{-\mathrm{nper}}} = £0.07/\mathrm{kWh}$$

C. DSR Energy Utilization

DSR energy utilization can be calculated from the actual DSR energy participation over the available DSR energy on the network, as:

$$\mathrm{DSR_{EU}} = \frac{\mathrm{DSR_{EAc}}}{\mathrm{DSR_{EAv}}}$$

G. Maximum Threshold of Energy-Based DSR Incentive

The maximum threshold of the incentive for this study is obtained at the point where the DSR energy utilization is equal to 100%, as written as:

$$\mathrm{DSR_{IncMax}} = \mathrm{DSR}_{\mathrm{IR}} * 100\% * \mathrm{DSR_{EAc}} = £7{,}843.00$$

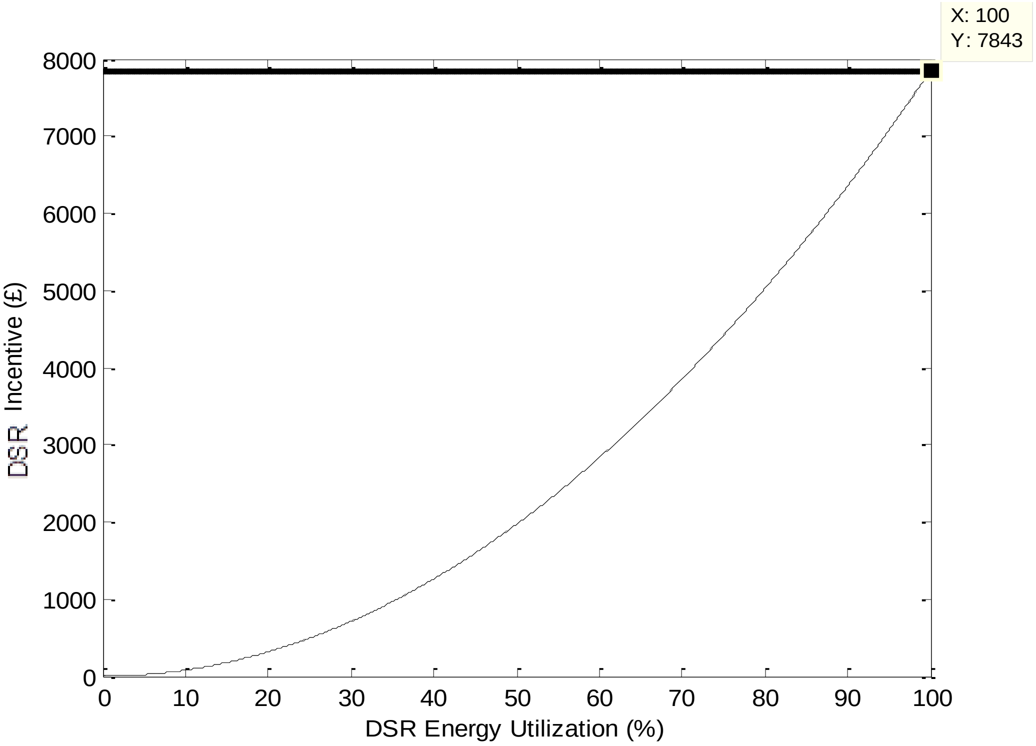

Figure 6.6 Energy-based DSR Incentive for Case Study 4

Figure 6.6 shows the graph of energy-based DSR incentive for case study 4. The energy-based DSR incentive will increase exponentially in accordance with the increase of DSR energy utilization. The maximum threshold of energy-based DSR incentive of £7,842.98 will be given to the DNO if the available DSR energy can be fully utilized, where DSR energy utilization is equal to 100%.

6.2.5 DG Connection at a Generation-dominated Busbar

Figure 6.7 shows the impact of connecting a new DG at one of generation-dominated busbars, i.e. at Bus11-6. The new DG is assumed to be an onshore wind generation with a capacity of 4.5MVA. This connection causes the standard capacity of the line between Bus11-6 and Bus11-7 is exceeded. As shown, the power flowing through this line is 8.998MVA, which is exceeding the line's standard capacity of 7.049MVA.

In order to accommodate all DG capacity connected to Bus11-6, the line between Bus11-6 and Bus11-7 needs to be reinforced, i.e. by upgrading the line's capacity up to 10.288MVA.

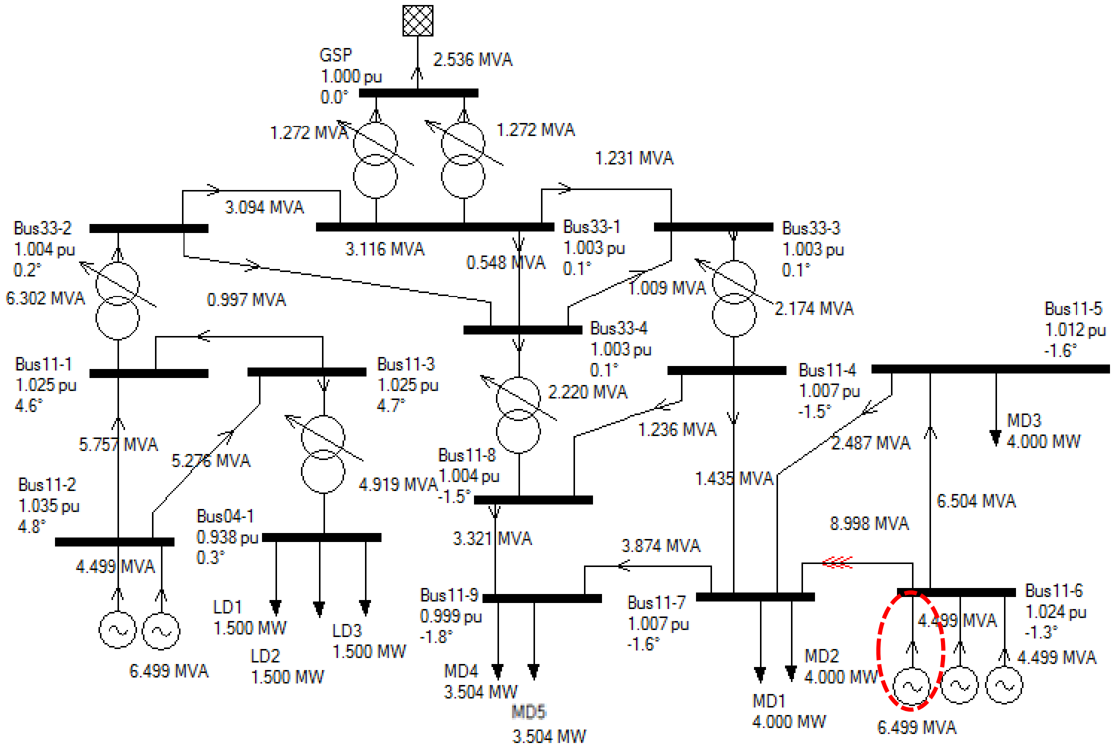

Figure 6.7 Impact of a New DG Connection on Network's Power Flow

After the line between Bus11-6 and Bus11-7 has been upgraded, the load flow analysis results of the network will change, as depicted in figure 6.8.

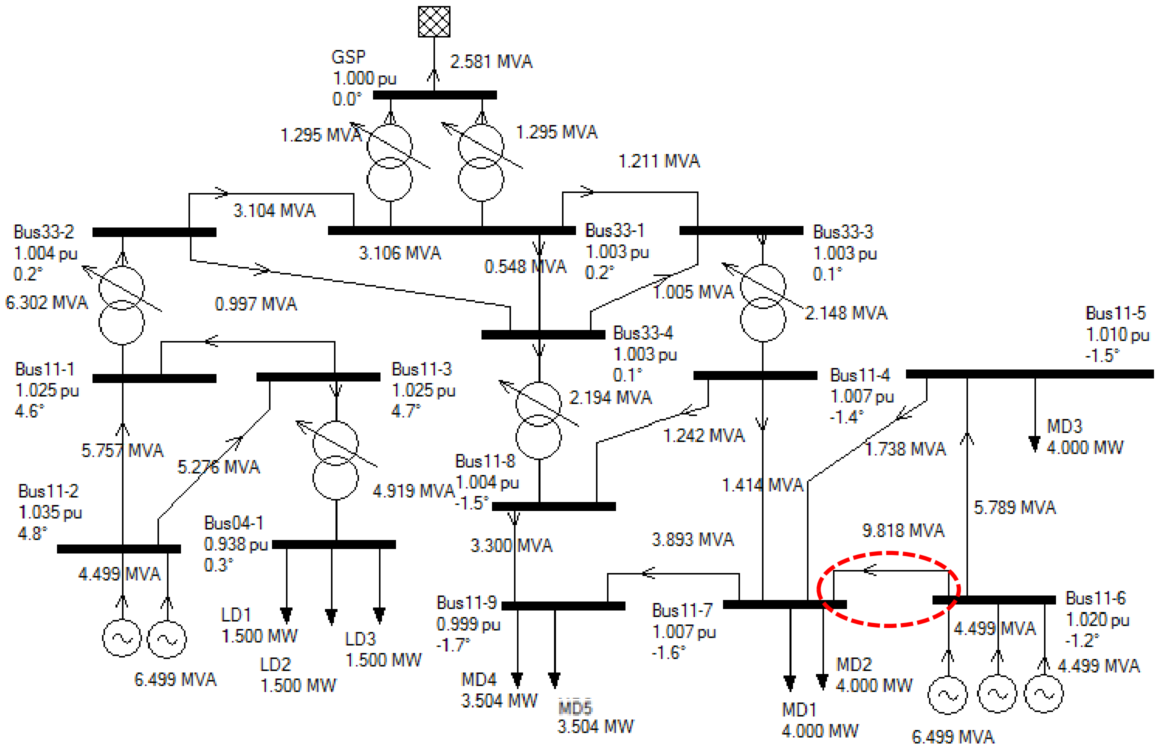

Figure 6.8 Impact Network Reinforcement on Network's Power Flow

As depicted in figure 6.8, by reinforcing the line between Bus11-6 and Bus11-7, the power flow of the line does not exceed its capacity standard, so that, the network can accommodate all capacity of the connected DGs. However, the power flow on the line between Bus11-6 and Bus11-7 increases from 8.998MVA to 9.818MVA. This due to the increase of line capacity will increase the portion of power which is flowing through the line. As a result, the portion of power which is flowing through other line will decrease. This can be seen from the decrease of power flow on the line between Bus11-6 and Bus11-5, from 6.504MVA down to 5.789MVA.

6.2.6 Implementation of Energy-based DG Incentive

A. Network Reinforcement Cost

The required reinforcement cost for this DG connection has been examined in chapter 2. The cost components considered in the calculation process to determine DG incentive only include the shared-use connection assets cost, which is estimated equal to £183,600.00.

B. Minimum Requirement for DG Energy to be conveyed

The new DG that will be connected to Bus11-6 is assumed to be an onshore wind generation with the capacity of 4.5MVA. Given the power factor ($\mathrm{DG_{p,pf}}$) = 0.9, the capacity factor ($\mathrm{DG_{p,cf}}$) = 0.35, the DG operational time ($\mathrm{DG_{p,oprtime}}$) = 8760 hours, and the levelised cost of energy generation ($\mathrm{DG_{p,LCOEG}}$) = £75/MWh, the minimum required energy to be conveyed can be obtained equal to 3,543MWh. This is equal to 28.5% utilization of the available DG energy of 12,417MWh. The details of the calculation process are examined in chapter 2.

C. Minimum and Maximum Thresholds of Energy-based DG Incentive

The minimum and maximum thresholds of energy-based DG incentive for the connection of a new DG to Bus11-6 can be seen in figure 6.9. The graph shows that the energy-based DG incentive for DNOs will increase exponentially in accordance with the increase of DG Energy Utilization.

The minimum incentive of £398.90 will be given to the DNO if the connected DG can conveyed 28.5% of its available energy during one year period. If the connected DG cannot meet this minimum requirement, the incentive for DNO will be equal to 0.

Meanwhile, the maximum incentive of £4,898.00 will be given to the DNO if the available DG energy of 12,417MWh can be fully utilized.

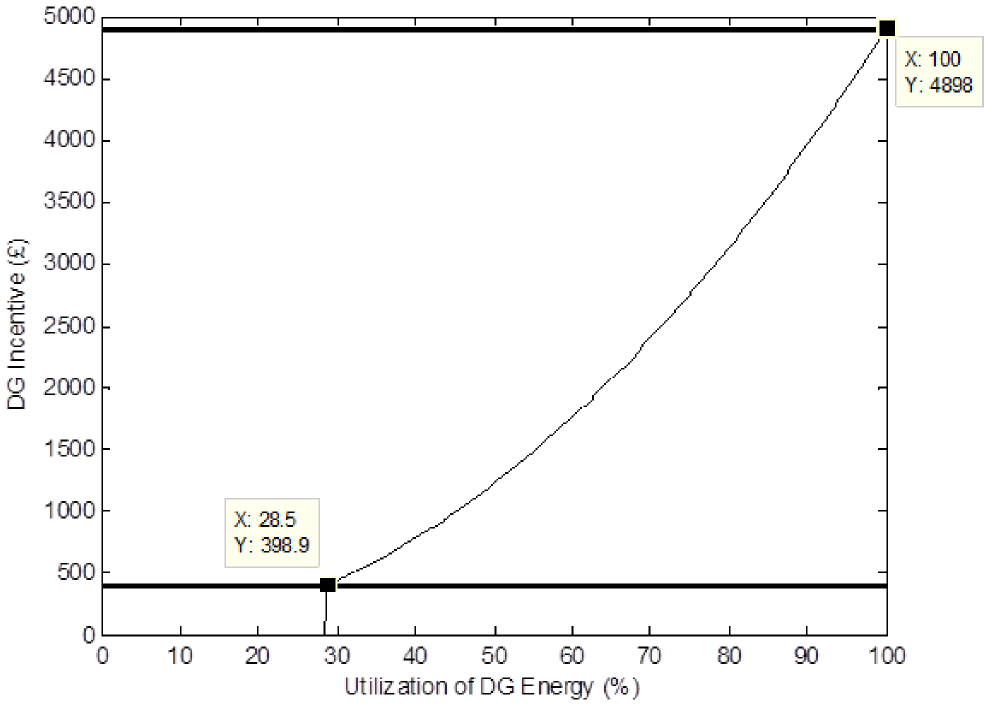

Figure 6.9 The Thresholds of Energy-based DG Incentive for Wind Generation

6.2.7 Impact of Network Reinforcement on Single Outage (N-1) Contingency

The network reinforcement is carried out by upgrading the capacity of the line between Bus11-6 and Bus11-7. By upgrading the line's capacity, all DG capacity connected to Bus11-6 can be accommodated. Beside this impact, this network reinforcement might also impact on the single outage (N-1) contingency of the network. The load flow analysis results of the (N-1) contingency, after the line between Bus11-6 and Bus11-7 is reinforced, are presented in table 6.7.

From Busbar	To Busbar	Rating	Network Capacity Utilization							
			B114-B117 Outage after Network Reinforcement		B117-B119 Outage after Network Reinforcement		B118-B119 Outage after Network Reinforcement		DG3 Outage after Network Reinforcement	
		(MVA)	(MVA)	(%)	(MVA)	(MVA)	(%)	(MVA)	(MVA)	(%)
GSP	Bus33-1	40.000	1.281	3%	1.228	3%	1.240	3%	2.174	5%
GSP	Bus33-1	40.000	1.281	3%	1.228	3%	1.240	3%	2.174	5%
Bus33-2	Bus33-1	15.433	3.089	20%	3.063	20%	3.114	20%	1.908	12%
Bus33-2	Bus11-1	10.000	6.302	63%	6.302	63%	6.302	63%	6.297	63%
Bus11-1	Bus11-2	7.049	5.757	82%	5.757	82%	5.757	82%	5.756	82%
Bus11-1	Bus11-3	7.049	0.997	14%	0.997	14%	0.997	14%	0.999	14%
Bus11-3	Bus04-1	7.500	4.919	66%	4.919	66%	4.919	66%	4.925	66%
Bus33-4	Bus11-8	10.000	2.301	23%	2.330	23%	2.080	21%	5.286	53%
Bus11-8	Bus11-9	7.049	4.336	62%	7.096	101%			5.630	80%
Bus33-1	Bus33-4	15.433	0.546	4%	0.459	3%	0.557	4%	2.411	16%
Bus33-1	Bus33-3	15.433	1.174	8%	1.235	8%	1.258	8%	3.811	25%
Bus33-3	Bus11-4	10.000	2.047	20%	2.148	21%	2.313	23%	5.224	52%
Bus11-3	Bus11-2	7.049	5.276	75%	5.276	75%	5.276	75%	5.278	75%
Bus11-4	Bus11-8	7.049	2.047	29%	4.959	70%	2.080	30%	0.482	7%
Bus33-3	Bus33-4	15.433	0.942	6%	0.959	6%	1.127	7%	1.415	9%
Bus33-2	Bus33-4	15.433	3.121	20%	3.140	20%	3.097	20%	4.283	28%
Bus11-5	Bus11-7	7.049	1.738	25%	1.739	25%	1.738	25%	0.065	1%
Bus11-9	Bus11-7	7.049	3.756	53%			7.097	101%	1.515	21%
Bus11-4	Bus11-7	7.049			3.761	53%	4.383	62%	4.682	66%
Bus11-7	Bus11-6	10.288	9.818	95%	9.818	95%	9.818	95%	5.097	50%
Bus11-5	Bus11-6	7.049	5.789	82%	5.789	82%	5.789	82%	3.971	56%

Table 6.7 Load Flow Analyses after the Network Reinforcement

As shown in table 6.7, after the line between Bus11-6 and Bus11-7 is upgraded, the outage of the line between Bus11-4 and Bus11-7 will not disrupt the operation of the network. Neither does the outage of DG3 at Bus11-6. This can be seen from the network capacity utilization of other lines which are still less than 100% following these two outages.

However, for other two outages, i.e. the outage of the line between Bus11-7 and Bus11-9 and the outage of the line between Bus11-8 and Bus11-9 still causes the network capacity utilization of other lines to exceed 100%. This can be explained further by using figure 6.10 and 6.13.

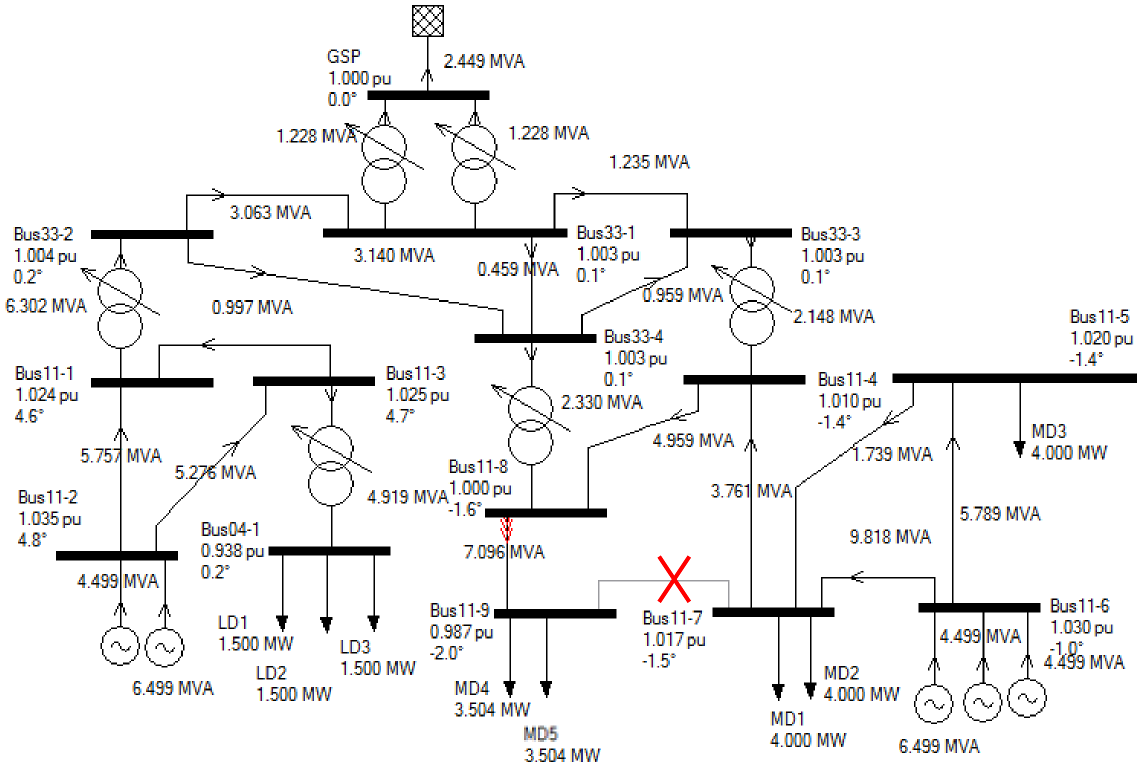

Figure 6.10 Load Flow Analysis for the Line outage between Bus 11-7 and Bus11-9 after Network Reinforcement

As presented in figure 6.10, the outage of the line between Bus11-7 and Bus11-9 causes the power flow on the line between Bus11-8 and Bus11-9 increases to 7.096MVA, exceeding its capacity standard. The power flow is depicted on the direction from Bus11-8 to Bus11-9, which means the power is used to supply demand connected to Bus11-9.

In order to deal with this condition, the demand connected at Bus11-9 should be reduced. The load flow results after reducing demand at Bus11-9 are shown in figure 6.11

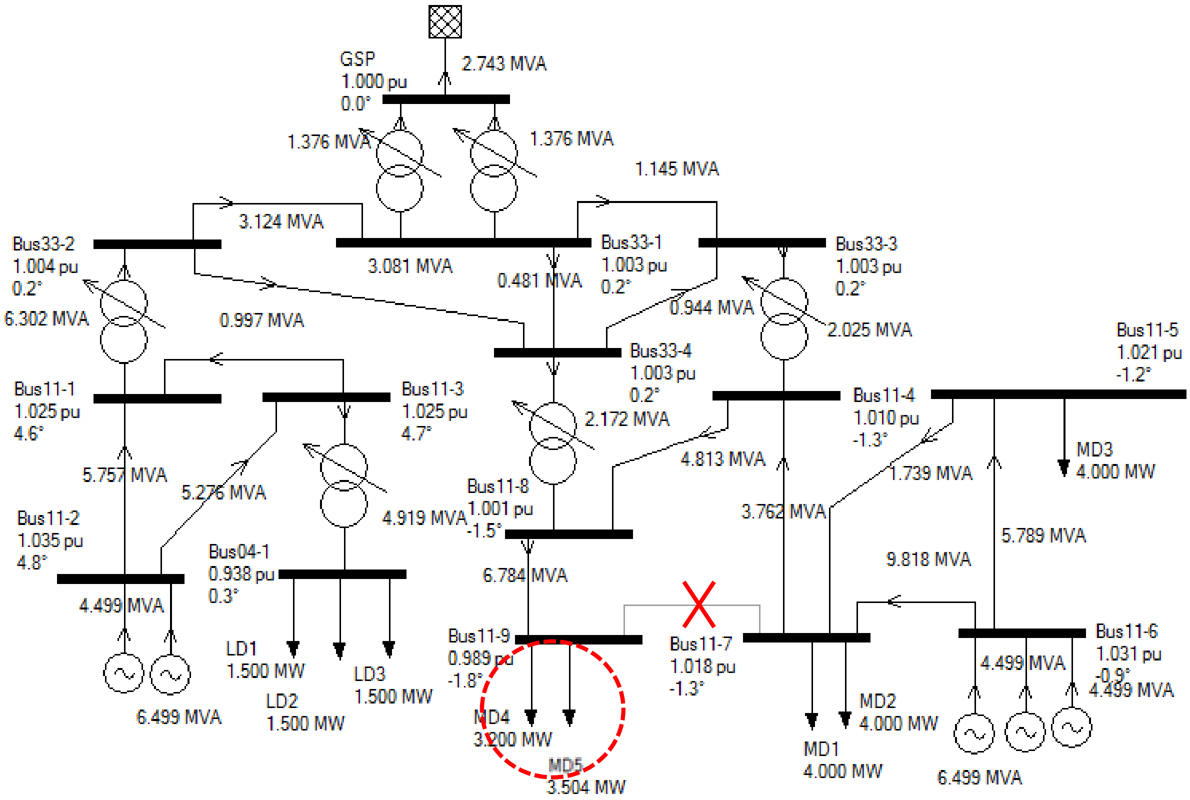

Figure 6.11 Load Flow Analysis after Reducing Demand at Bus11-9 Following the Outage of the Line between Bus11-7 and Bus11-9

Figure 6.11 shows the impact of reducing demand at Bus11-9 on the power flow of the line between Bus11-8 and Bus11-9. The demand reduction mechanism is carried out by reducing 0.3MW of MD4. This reduction can decrease the power flow on the line between Bus11-8 and Bus11-9 from 7.096MVA down to 6.784MVA, less than its capacity standard.

Meanwhile, the outage of the line between Bus 11-8 and Bus11-9 after the network reinforcement took place, causes the network capacity utilization of the line between Bus11-7 and Bus11-9 to exceed 100%, as depicted in figure 6.13.

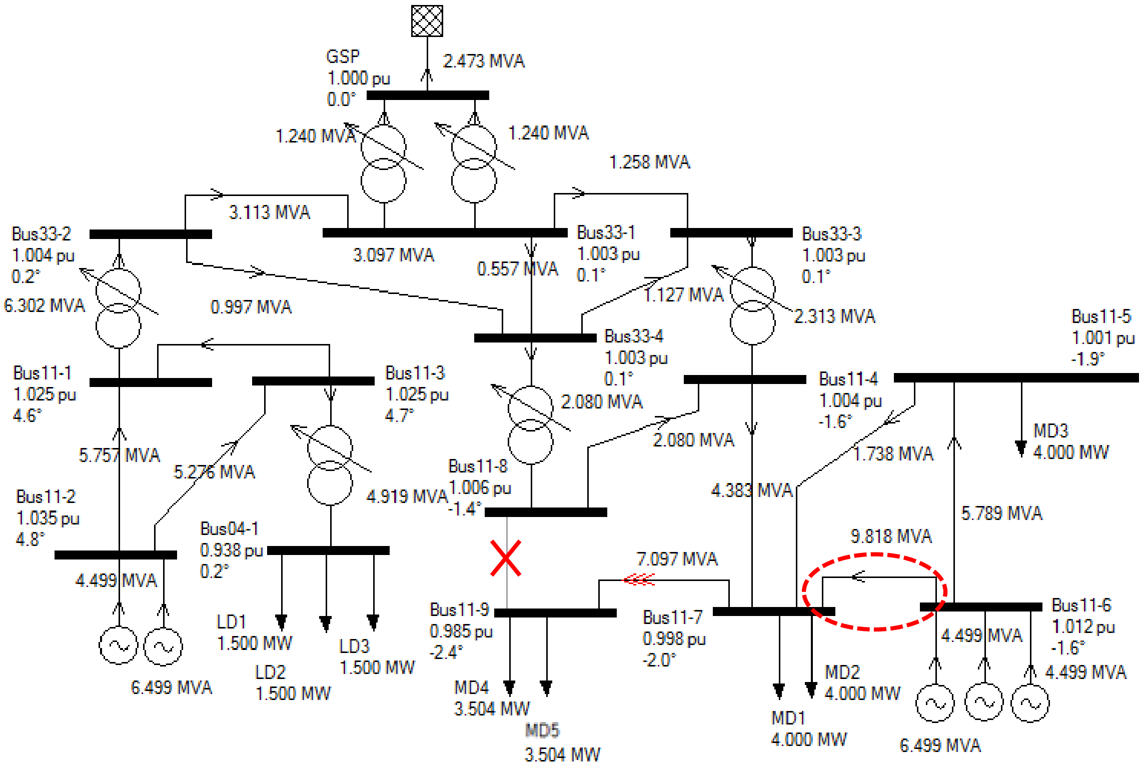

Figure 6.12 Load Flow Analysis for the Line outage between Bus 11-8 and Bus11-9 after Network Reinforcement

As shown in figure 6.12, the outage of the line between Bus11-8 and Bus11-9 causes the power flow on the line between Bus11-7 and Bus11-9 increases to 7.097MVA, exceeding its capacity standard. The power flow is depicted on the direction from Bus11-7 to Bus11-9, which means the power is used to supply demand connected to Bus11-9.

In order to deal with this condition, the demand connected at Bus11-9 should be reduced. The load flow results after reducing demand at Bus11-9 are shown in figure 6.13.

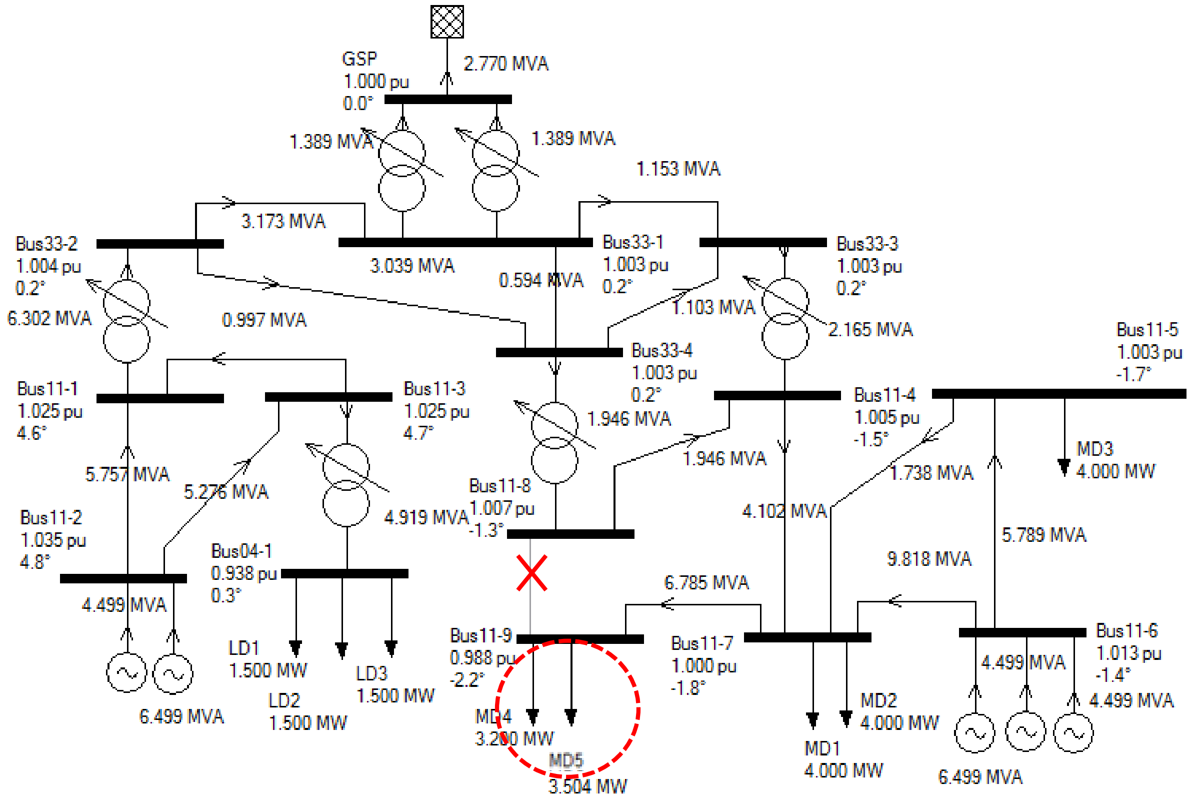

Figure 6.13 Load Flow Analysis after Reducing Demand at Bus11-9 Following the Outage of the Line between Bus11-8 and Bus11-9

Figure 6.13 shows the impact of reducing demand at Bus11-9 on the power flow of the line between Bus11-7 and Bus11-9. The demand reduction mechanism is carried out by reducing 0.3MW of MD4. This reduction can decrease the power flow on the line between Bus11-7 and Bus11-9 from 7.097MVA down to 6.785MVA, less than its capacity standard.

6.2.8 Impact of Network Reinforcement on the Functionality of DSR Programme

As described in section 6.27, the network reinforcement, which is carried out by upgrading the capacity of the line between Bus11-6 and Bus117, has affected the single outage (N-1) contingency of the network. This impact of network reinforcement on the functionality of DSR programme on the network can be summarised in table 6.8.

Single Outage (N-1) Contingency	DSR Mechanisms	Before Network Reinforcement		After Network Reinforcement	
		Participants	**Capacity (MW)**	**Participants**	**Capacity (MW)**
Outage of the line between Bus11-4 and Bus11-7	Demand Reduction & On-site Generation	MD1, MD2, MD3, MD4, MD5	(0.3+0.2) x 5	-	
Outage of the line between Bus11-7 and Bus11-9	Demand Reduction & On-site Generation	MD1, MD2, MD3, MD4, MD5	(0.3+0.2) x 5	MD4	0.30
Outage of the line between Bus11-8 and Bus11-9	Demand Reduction & On-site Generation	MD1, MD2, MD3, MD4, MD5	(0.3+0.2) x 5	MD4	0.30
DG3 is out of service	Demand Reduction & On-site Generation	MD1, MD2, MD3, MD4, MD5	(0.3+0.2) x 5	-	
Demand Shifting		LD1, LD2, LD3	0.45	LD1, LD2, LD3	0.45
Total			2.95		1.05

Table 6.8 Comparison of DSR Participation

Table 6.8 shows the comparison of the required DSR participation from the customers related to the single outage (N-1) contingency of the network, before and after network reinforcement. Where, the network reinforcement is carried out in order to accommodate a new DG connection on a generation-dominated busbar.

As presented in table 6.8, network reinforcement can reduce the functionality of DSR mechanism. In other words, DSR activities are not required in particular outage events due to the network has been upgraded. The reduction of the DSR activities will impact on the reduction of available DSR energy on the network, which in turn, it will impact on the value of energy-based DSR incentive to be given to the distribution network operators (DNO).

6.2.9 Impact of Network Reinforcement on Energy-Based DSR Incentive

There are three mechanisms in implementing DSR programmes, including demand reduction, running on-site generations and demand shifting. Based on the previous analysis of this case, network reinforcement will impact on the requirement of DSR participation. In terms of demand reduction and running on-site generation mechanisms, the requirement can be met by one customer group, i.e. MD4, while in terms of demand shifting mechanism, the participation from LD1, LD2 and LD3 is still required.

A. DSR Costs

The costs that must be borne by the DNO in implementing DSR programme include the capital cost and the operational cost. The breakdown of the required investment cost is given in table 6.9. It is assumed that the required capital cost is estimated to be £35,000.00 per site and the required operational cost to implement DSR programme on the network is estimated as 5% from the total capital cost [85].

Cost Category	Per Site (£)	Units	Total (£)
Capital Cost	35,000.00	4	140,000.00
Operational Cost	5% of total capital cost		7,000.00
Total			147,000.00

Table 6.9 DSR Investment Cost for Case Study 5

As presented in table 6.9, the capital cost is needed to implement DSR programme at four sites, i.e. MD4, LD1, LD2 and LD3. So, in total, the required investment cost is estimated to be £147,000.00

B. DSR Available Energy

The customers, who participate in demand reduction and running on-site generation mechanisms, are required to reduce their energy demand and to operate their on-site generation for 2.5 hours at the event of a failure. While the customers of demand shifting mechanism are required to shift their energy consumption for one hour, from peak demand times to off-peak demand times, during winter and autumn seasons (180 days). Hence, the available DSR energy on the network can obtained as presented in table 6.10.

Single Outage (N-1) Contingency	DSR Mechanisms	Participants	Capacity (MW)	Duration (hours)	Available DSR Energy (kWh)
Outage of the line between Bus11-7 and Bus11-9	Demand Reduction	MD4	0.30	2.5	750
Outage of the line between Bus11-8 and Bus11-9	Demand Reduction	MD4	0.30	2.5	750
Demand Shifting		LD1, LD2, LD3	0.45	180	81,000
Total					82,500

Table 6.10 Available DSR Energy for Case Study 5

D. Unit Cost of DSR Incentive Rate

Given the total DSR cost of £147,000.00 and total available DSR energy of 82,500 kWh, the unit cost of energy-based DSR incentive is obtained as:

$$\mathrm{DSR_{UC}} = \frac{\sum \mathrm{DSR_{Cost}}}{\mathrm{DSR_{EAv}}} = £1.78/\mathrm{kWh}$$

E. Energy-Based DSR Incentive Rate

By considering the WACC of 5.6% and additional 1% rate of return and the lifetime of DG connection assets of 15 years, the incentive rate can be obtained from equation (5.6) as:

$$\mathrm{DSR_{IR}} \quad = \quad \frac{\mathrm{DSR_{UC}} * (1-80\% + \mathrm{WACC} + \mathrm{additional\ rr}) * \mathrm{WACC}}{(1-(1+\mathrm{WACC}))^{-\mathrm{nper}}} = £0.05/\mathrm{kWh}$$

C. DSR Energy Utilization

DSR energy utilization can be calculated from the actual DSR energy participation over the available DSR energy on the network, as:

$$\mathrm{DSR_{EU}} = \frac{\mathrm{DSR_{EAc}}}{\mathrm{DSR_{EAv}}}$$

G. Maximum Threshold of Energy-Based DSR Incentive

The maximum threshold of the incentive for this study is obtained at the point where the DSR energy utilization is equal to 100%, as written as:

$$\mathrm{DSR_{IncMax}} = \ \mathrm{DSR}_{\ \mathrm{IR}} * 100\% * \mathrm{DSR_{EAc}} = £3{,}921.00$$

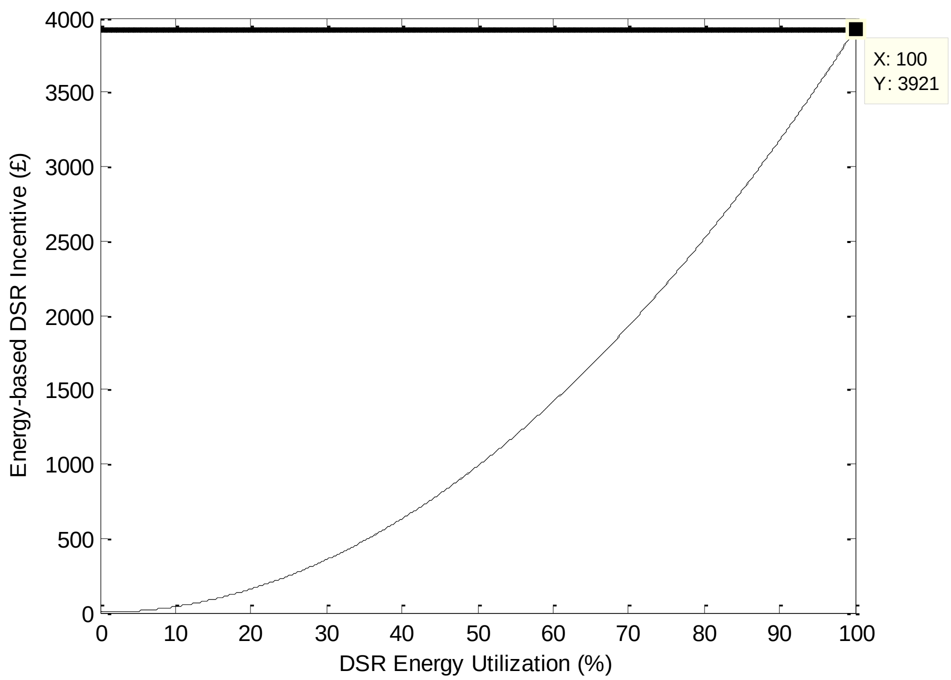

Figure 6.14 Energy-based DSR Incentive for Case Study 5

Figure 6.14 shows the graph of energy-based DSR incentive for case study 5. The energy-based DSR incentive will increase exponentially in accordance with the increase of DSR energy utilization. The maximum threshold of energy-based DSR incentive of £3,921.00 will be given to the DNO if the available DSR energy can be fully utilized, as required.

6.3 COMPARISON BETWEEN SINGLE AND MIXED ENERGY-BASED DG AND DSR INCENTIVE

The terms of single incentive mechanism refers to the implementation of one incentive mechanisms, either energy-based DG incentive or energy-based DSR incentive separately, without considering the relation amongst them. Meanwhile, mixed energy-based DG and DSR incentives mechanism indicates the implementation of both incentive mechanisms on the same network, simultaneously. The comparison between single and mixed energy-based DG and DSR incentives can be summarised in table 6.11.

Components	**Single Energy-based Incentive Mechanism**		**Mixed Energy-based Incentive Mechanism**	
	DSR Incentive	DG Incentive	DSR Incentive	DG Incentive
Investment Cost (£)	294,000.00	183,600.00	147,000.00	183,600.00
Available Energy (kWh)	106,000	12,417.30	82,500	12,417.30
Unit Cost (£/kWh)	2.77	14.79	1.78	14.79
Incentive Rate (£/kWh)	0.07	0,394	0.05	0,394
Minimum Energy Utilization	-	28.5%	-	28.5%
Minimum Threshold (£)	-	398.88	-	398.88
Maximum Threshold (£)	7,842.98	4,897.86	3,921.00	4,897.86

Table 6.11 Comparison between Single and Mixed Energy-based Mechanism

As presented in table 6.11, the total investment cost that must be borne by DNOs to apply energy-based DG and DSR incentive mechanisms separately is more than the one for applying mixed energy-based mechanism. In this case, if DNOs apply both mechanisms separately, they are required to invest approximately of £477,600.00. However, by applying both mechanisms simultaneously, they will spend less investment cost, approximately of £330,600.00. Although the required investment is different, the benefits from connecting a new DG and implementing DSR programme remain the same, for both scenarios.

As the required investment cost is lower, the amount of incentives for DNOs will be lower, too. From the energy regulator’s point of view, who is responsible to incentivise the DNOs, this also becomes a benefit. They will be required to give less incentive to the DNOs, but in return, the benefits from DG connection and DSR implementation remain the same.

Hence, the mixed energy-based DG and DSR incentives mechanism will encourage DNOs to be more effective in providing DG connection and implementing DSR programme on their networks.

6.4 CHAPTER SUMMARY

There is an interaction between providing DG connection and implementing DSR on the same network. Based on the single outage (N-1) contingency analysis of the case study, the connection of a new DG which leads to network reinforcement, will impact on the functionality of DSR.

The participation of customers in DSR programme is required to deal with the single outage (N-1) contingency on the network, in a condition where the outage can disrupt the network operation. By reinforcing the network, a particular outage might not impact on the operation of the network, so that, this will not require customers to participate in DSR programme. Referring to this, DNOs do not necessarily need to invest in DSR programme. As a result, this can reduce the required investment cost to provide DG connection and to implement DSR programme on their network.

The mixed energy-based DG and DSR incentive mechanism considers the interaction between providing DG connection and implementing DSR programme on the same network. The incentives will be given to the DNOs based on the utilization of DG and DSR energy on the network and its relation with the required network reinforcement. It is expected that this mechanism can encourage DNOs to be more effective in their investments related to DG connection and DSR implementation.

7 CONCLUSION AND FUTURE WORK

7.1 CONCLUSION

7.1.1 Development of DG and DSR

The deployment of distributed generation (DG) and the implementation of demand side response (DSR) programme have significant impact on achieving the target in reducing greenhouse gasses emissions and increasing the penetration of renewable energy sources in electricity production. Since most of DGs come from renewable resources they can contribute in reducing carbon emissions from the electricity sector and increasing the use of renewable sources to replace fossil fuels. Meanwhile, the implementation of DSR, through demand reduction and demand shifting mechanisms will impact on the more efficient use of electricity generation as well as minimising the use of less efficient generation plants, which mostly come from fossil fuelled power plants.

In some countries, the penetration of DGs on the distribution network is quite low. The data shows that DG only contributes 1.36% of the total electricity generation in Australia. In the United Kingdom, 7.5% of the total electricity generation comes from DGs. While in the United States of America, the penetration of DGs is around 18.98% of the total electricity generation. The obstacles in the deployment of DGs include payment warranty for exported electricity, inadequate information, planning permission, electricity industry issues and incentives for DNOs. One of the key issues is related to the incentives for DNOs. Currently, DNOs have not received appropriate incentives to provide DG connection on their networks.

The implementation of DSR programme on the distribution network also encountered some barriers. The obstacles to the implementation of DSR include several things, amongst which are low participation of relevant parties, use of advance technologies, regulation and incentives for DNOs. The incentives for DNOs become one of the key issues that must be taken into account. DNOs require appropriate incentives to implement and develop DSR programme on their distribution networks.

Thus, of all the existing barriers associated with the deployment of DG and DSR implementation, appropriate incentives for DNOs seem to be a common barrier that must be addressed.

7.1.2 Current Incentives for DNOs related to DG Connection and DSR Implementation

The incentives for DNOs include DG Incentive and DSR Incentive, aims to give financial support to the Distribution Network Operators (DNOs) in order to provide the connection of distributed generation (DG) and to facilitate the implementation of demand side response (DSR) on the distribution network.

Current DG incentive, which is applied in the United Kingdom, is given to the DNOs based on the capacity (kW) of the connected DG. The higher the DG capacity connected to the network, the higher the amount of incentive for the DNOs. In addition, the incentive is uniform across the country.

This mechanism might give unfair treatment for every DG connection considering two reasons. The first reason is related to the technology used to generate energy. Each technology has different value of DG parameters, including the capacity factor, the operational time and the levelised cost of energy generation. These parameters are used to determine the amount of energy that can be generated from DG. So that, at the same standard capacity, different DG technology will generate different amount of energy. The second reason is related to the location where a DG is connected to the distribution network. This factor will impact on the investment cost needed to provide connection. In a rural or remote location, the investment cost for DG connection is higher than the location which is near to the existing network. The location of DG connection will also impact on the number of affected components at a particular network configuration. The more the number of components needs to be upgraded, the higher the investment cost required.

Therefore, in terms of DG incentives for DNOs, this research proposes a new approach to incentivise DNOs associated with DG connection, called energy-based DG incentive mechanism. In this mechanism, DNOs will be incentivised based on the utilization of the available DG energy on the network and its relation with the required investment. The higher the DG energy utilization, the higher the incentive for DNOs.

Regarding the incentives for DNOs to implement DSR programme, different mechanisms have been applied in some countries, including Australia and USA. Some of the mechanisms aim to allow DNOs to recover their investment cost or forgone revenue related to DSR initiatives, as implemented in demand management incentive and rate of return mechanisms. Other mechanisms aim to allow DNOs to receive a percentage share or saving compensation as a result of DSR implementation on their distribution networks, as implemented in shared shavings and avoided cost mechanisms. Currently, those DSR incentive mechanisms operate independently without any correlation between them.

Therefore, in terms of DSR incentive for DNOs, this research proposes a new mechanism called energy-based DSR incentive mechanism. This mechanism aims to allow DNOs to recover their investment costs based on the utilization of available DSR energy on the network. The higher the DSR energy utilization, the higher the incentive for the DNOs.

7.1.3 Key Findings of the Energy-based DG Incentive for DNOs

This research proposes a new approach to incentivise DNOs associated with DG connection, called energy-based DG incentive mechanism. In this mechanism, DG incentive for DNOs is calculated based on the utilization of the available DG energy on the network and its relation with the required investment. The higher the DG energy utilization, the higher the incentive given to the DNOs.

There are minimum and maximum thresholds for the energy-based DG incentive. The maximum threshold of the incentive will be given to the DNOs if the available DG energy can be fully utilized. The minimum threshold of the incentive is given to the DNOs when the connected DG only delivers the minimum required energy to be conveyed. If the DNOs cannot meet this requirement, they will not be incentivised.

There are seven types of DG technologies, including biomass, geothermal, CCGT CHP, offshore wind, hydro, onshore wind and solar PV which are examined in this research. The aim of this assessment is to find out the impact of DG technology on the value of the energy-based DG incentive that will be given to the DNOs. The analysis shows that different DG technologies will generate different amount of energy output. By assuming the capacity of DG connected to the network is 4.5MVA and the estimated reinforcement cost of £183,600.00, the DG incentive rates for different DG technologies will vary, in the range between £1.53/MWh and £14.19/MWh.

Since different DG technology will generate different energy output, the minimum requirement for energy to be conveyed will vary amongst different DG technologies, between 13.52% and 39.63% of the available DG energy. These values will result in different minimum threshold of energy-based DG incentive for DNOs. However, if the DNOs cannot meet the minimum requirement for energy to be conveyed, they will not be incentivised.

Meanwhile, the maximum threshold of energy-based DG incentive is given when the connected DG can deliver all their available energy, i.e. when the DG energy utilization is equal to 100%. Since the reinforcement cost to provide DG connection is assumed to be the same for all DG technologies, the maximum threshold of the incentive for all types of DG technology will be the same, equal to 20% of the required reinforcement cost.

The location of DG connection on the network will also determine the value of energy-based DG incentive for the DNOs. Based on the analysis result of this research, the increase of the line's length by 3000m will increase the incentive rate by £1.71/MWh.

Another considered factor is related to the network configuration. The configuration of a particular network will determine the number of components that might be affected by the connection of a new DG to the network. The more the number of components needs to be upgraded, the higher the investment cost required. Based on the analysis results of the case studies in this thesis, the minimum and maximum threshold of energy-based DG incentive will adjust to the increase of the required reinforcement cost to provide DG connection. The higher the required reinforcement cost, the higher the incentive thresholds for the DNOs.

Hence, comparing with current DG incentive mechanism, the proposed energy-based DG incentive mechanism can reflect the effectiveness of DNOs to deal with the required reinforcement cost to provide DG connection and the utilization of available DG energy on the network.

7.1.4 Key Findings of the Energy-based DSR Incentive for DNOs

In terms of DSR incentive mechanism, this research proposes a new mechanism called energy-based DSR incentive. This mechanism aims to incentivise DNOs in association with DSR implementation on their network.

There are two factors which are considered in the implementation of energy-based DSR incentive mechanism. The first factor is related to the required investment cost to implement DSR programme on the distribution network. The maximum threshold of energy-based DSR incentive will adjust to the increase of the investment cost for DSR implementation. The higher the required investment cost, the higher the incentive thresholds for the DNOs.

The second factor is related to the available DSR energy participation on the network. The energy-based DSR incentive is calculated based on the utilization of available DSR energy on the network. The higher the DSR energy utilization, the higher the incentive for the DNOs.

The maximum threshold of the incentive will be given to the DNOs if they can fully utilize the available energy from DSR participants on their network, as required.

Therefore, the proposed energy-based DSR incentive mechanism can reflect the effectiveness of DNOs to deal with the required investment cost to implement DSR programme and the utilization of available DSR energy on the network.

7.1.5 Key Findings of the Mixed Energy-based DG and DSR Incentives for DNOs

The mixed energy-based DG and DSR incentives mechanism aims to incentivise DNOs in association with their investment in providing DG connection and implementing DSR programmes. This mechanism considers the interaction between connecting DG and implementing DSR programme on the same distribution network.

DSR mechanisms, including demand response and running on-site generation, aim to response to the single outage (N-1) contingency. In a case where the DG connection requires a particular network to be reinforced, the network reinforcement might impact the functionality of DSR on that particular network. Following network reinforcement, the single outage (N-1) contingency might not impact on the operation of the network, so that, the participation in DSR mechanisms is not required. This indicates that the DNOs do not necessarily need to invest in DSR programme on that particular network but they might be still required to implement DSR programme on other parts of the network.

The mixed energy-based DG and DSR incentives mechanism is allowing DNOs to recover necessary investment related to the connection of DGs and the implementation of DSR. The incentives are calculated based on the utilization of the available DG and DSR energy on the network. The higher the utilization of the available DG and DSR energy, the higher the incentives for DNOs will be.

Therefore, if the DNOs cannot fully utilize their investment in providing DG connection and implementing DSR programme, they will not be able to recover their investment cost. Through the mixed energy-based DG and DSR incentive, the DNOs are expected to be more effective in providing DG connection and implementing DSR programme on their networks.

7.2 THESIS LIMITATIONS

Parts of the objectives of the thesis are examining the impact of connecting a new DG to an existing distribution network, either to a generation-dominated area or to a demand-dominated area. The network configuration used in this thesis is an ideal network configuration which has some generation-only busbars and some demand-only busbars. This kind of network configuration is probably very rare in a real electricity system.

Also, this thesis examines the impact of DG connection and DSR implementation on distribution network separately. Further consideration should be taken into account by considering that DG connection and DSR implementation could affect each other, if they are applied on the same distribution network.

7.3 FUTURE WORK

The proposed energy-based DG incentive mechanism can be developed further by considering the increase in the number of DGs connected to the network. One of the benefits of the presence of DGs on the distribution network is that it can maintain supply reliability in distribution level. However, when the amount of DGs increases significantly, it will require the DNOs to reinforce and develop the network in order to optimize the utilization of available DG energy on the network. As a consequence, DNOs need extra costs for developing, operating and maintaining the network in order to fulfil the requirement.

On the one hand, a large number of DGs connected to the distribution network may cause DNOs to face financial and technical constraints, but on the other hand, this will give an opportunity to the transmission network operator (TNOs) to utilize the excess energy from the DG to unravel the transmission congestion. This requires good coordination between DNOs and TNOs, thus, the communication between the parties can be increased more intensively. Considering this, the energy-based DG incentive mechanism can be implemented to incentivise associated parties, either DNOs or TNOs, in association with the utilization of DG energy to release the congestion on transmission level and its relation with the required investment cost.

Regarding the energy-based DSR incentive mechanism, further development can be carried out by considering the utilization of available DSR participation to reduce the power flow and to flatten the peak demand on the transmission level. Demand reduction mechanism can be used to prevent high power flow which can lead the network components to fail or damage. Another DSR mechanism, the demand shifting mechanism, can be used to flatten the peak demand. By flattening the peak demand, the investment for network upgrade can be deferred. Considering these factors, the energy-based DSR incentive mechanism can be implemented to incentivise associated parties, either DNOs or TNOs, in association with the utilization of

DSR participation and its relation with the avoided investment to upgrade the network components.

Furthermore, the connection of a DG at a particular network, where the DSR programme is also applied, will impact on the reduction of the required investment cost. By considering the correlation between DG and DSR, the target of low carbon network can be achieved with lower investment cost. This can be considered to further develop the mixed energy-based DG and DSR incentive mechanism.

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Appendix 1 - Network Data

Name	Nominal Voltage (kV)	Control Type	Voltage Magnitude (pu)	Voltage Angle (deg)
GSP	275.000	Slack	1.000	
Bus33-1	33.000	PV	1.000	0.0
Bus33-2	33.000	PV	1.000	0.0
Bus33-3	33.000	PV	1.000	0.0
Bus33-4	33.000	PV	1.000	0.0
Bus11-1	11.000	PV	1.000	0.0
Bus11-2	11.000	PQ	1.000	0.0
Bus11-3	11.000	PV	1.000	0.0
Bus11-4	11.000	PV	1.000	0.0
Bus11-5	11.000	PV	1.000	0.0
Bus11-6	11.000	PQ	1.000	0.0
Bus11-7	11.000	PV	1.000	0.0
Bus11-8	11.000	PV	1.000	0.0
Bus11-9	11.000	PV	1.000	0.0
Bus04-1	0.400	PV	1.000	0.0

Table App-1.1 Busbars Data of the Reference Network

Name	Real Power Output (MW)	Reactive Power Output (MVAr)	Synch Resistance (pu)	Synch Reactance (pu)	Zero Seq Resistance (pu)	Zero Seq Reactance (pu)
DG1	4.050	1.960	0.085941	34.076.300	0.143592	1.135.880
DG2	5.850	2.830	0.152672	25.954.200	0.152672	1.068.700
DG3	5.850	2.830	0.152672	25.954.200	0.152672	1.068.700
DG4	4.050	1.960	0.085941	34.076.300	0.143592	1.135.880

Table App-1.2 Generators Data

Name	Standard Rating (MVA)	Resistance (pu)	Reactance (pu)	Susceptance (pu)	Zero Seq Resistance (pu)	Zero Seq Reactance (pu)
MVL-1	15.433	0.031426	0.019180	0.000548	0.059029	0.020411
MVL-2	15.433	0.031426	0.019180	0.000548	0.059029	0.020411
MVL-3	15.433	0.031426	0.019180	0.000548	0.059029	0.020411
MVL-4	15.433	0.031426	0.019180	0.000548	0.059029	0.020411
MVL-5	15.433	0.031426	0.019180	0.000548	0.059029	0.020411
MVL-6	7.049	0.146120	0.144701	0.000137	0.401475	0.158746
MVL-7	7.049	0.146120	0.144701	0.000137	0.401475	0.158746
MVL-8	7.049	0.146120	0.144701	0.000137	0.401475	0.158746
MVL-9	7.049	0.146120	0.144701	0.000137	0.401475	0.158746
MVL-10	7.049	0.146120	0.144701	0.000137	0.401475	0.158746
MVL-11	7.049	0.146120	0.144701	0.000137	0.401475	0.158746
MVL-12	7.049	0.146120	0.144701	0.000137	0.401475	0.158746
MVL-13	7.049	0.146120	0.144701	0.000137	0.401475	0.158746
MVL-14	7.049	0.146120	0.144701	0.000137	0.401475	0.158746
MVL-15	7.049	0.146120	0.144701	0.000137	0.401475	0.158746

Table App-1.3 Lines Data of the Reference Network

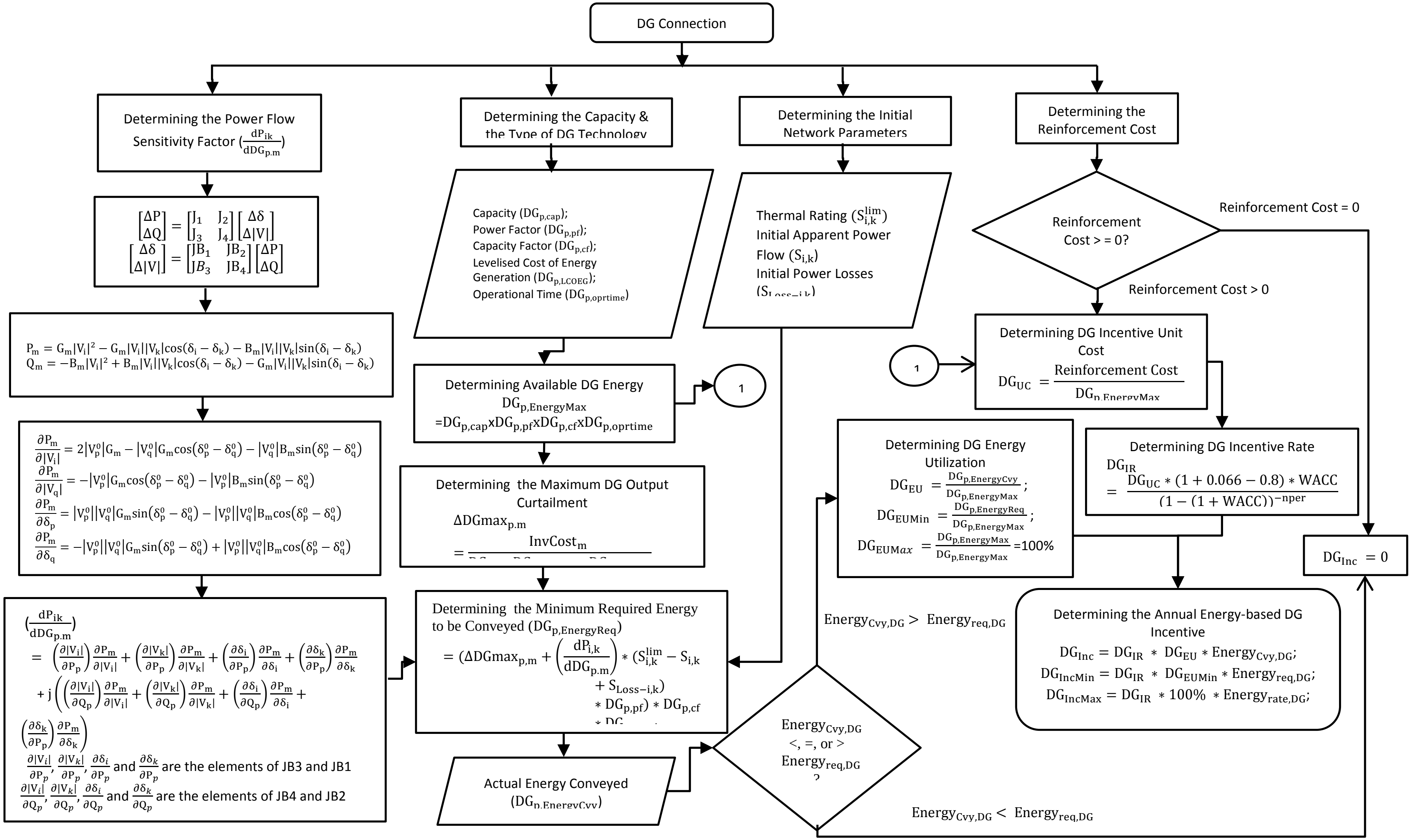
Name	Standard Rating (MVA)	Resistance (pu)	Reactance (pu)	Zero Seq Resistance (pu)	Zero Seq Reactance (pu)
TR1	40.000	0.015000	0.312250	0.012500	0.268750
TR2	40.000	0.015000	0.312250	0.012500	0.268750
TR3	10.000	0.072300	1.308000	0.065100	1.177000
TR4	10.000	0.072300	1.308000	0.065100	1.177000
TR5	10.000	0.072300	1.308000	0.065100	1.177000
TR6	7.500	0.414800	2.372000	0.373200	2.134800

Table App-1.4 Transformers Data of the Reference Network

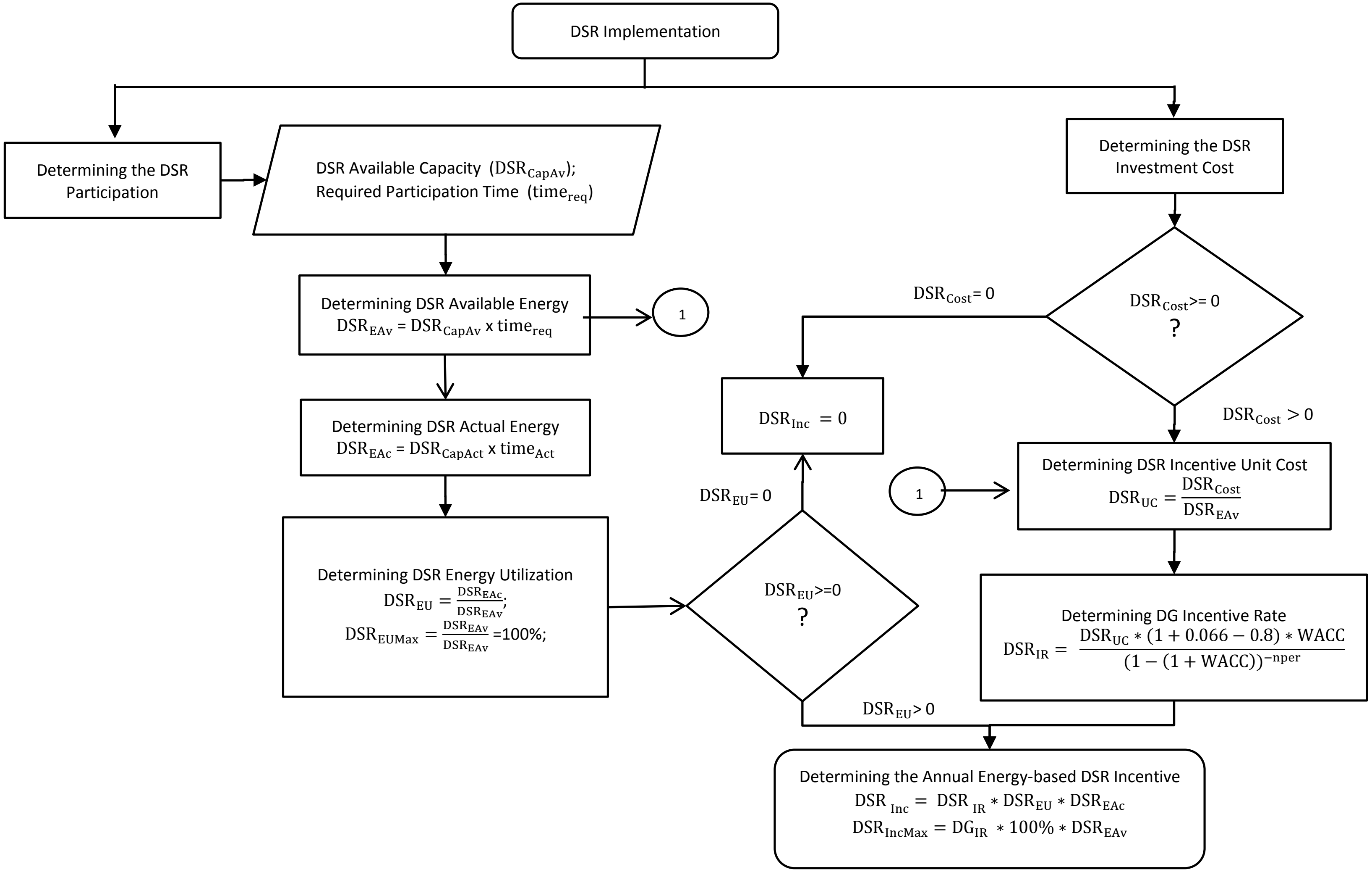
Name	Real Power (MW)	Reactive Power (MVAr)
MD1	3.800	1.250
MD2	3.800	1.250
MD3	3.800	1.250
MD4	3.330	1.090
MD5	3.330	1.090
LD1	1.200	0.900
LD2	1.200	0.900
LD3	1.200	0.900

Table App-1.5 Load Data

Appendix 2 – Full Flowchart for Energy-based DG Incentive Mechanism



Appendix 3 – Full Flowchart for Energy-based DSR Incentive Mechanism



Appendix 4 - Email Correspondences

Email 1. LTDS <LTDS@northernpowergrid.com>, 7 November 2014. *Network Upgrade for DSR Implementation*. Email to Mohammad Noor Hidayat <mnh22@bath.ac.uk>

Date: 11/07/14 15:43:33 GMT
From: LTDS <LTDS@northernpowergrid.com>
To: mnh22@bath.ac.uk <mnh22@bath.ac.uk>
Subject: RE: Network Upgrade for DSR Implementation

Parts: 1 Text part 6 KB

Dear Mohammad

You may find some useful information on your request in our Long Term Development Statement. Link below

http://www.northernpowergrid.com/long-term-development-statement

There is no charge for accessing the information and it provides quite a lot of background data.

There are two other sources of information that may be useful

http://www.networkrevolution.co.uk/
http://www.smarternetworks.org/

both websites will provide you projects and innovations that DNOs are looking at - these cover all aspects, however amongst these are projects on DSR.

Your questions seem to be covering two points. Adoption of DSR and the upgrading the distribution network to integrate Smart Metering To answer the two questions specifically:-

Upgrading the network to integrate Smart Metering

There is no upgrade required to the network to integrate Smart Metering - therefore no cost to the DNO. Smart Meters will be replaced by the Meter Provider companies, which are not related to us in any way.

On the topic of adoption of DSR

- Which parts of the network should be upgraded by the DNO?

No parts of the network would be upgraded by a DNO to allow DSR - one of the major drivers for DSR is that it defers upgrading (i.e. reinforcement). The distribution network is designed to provide demand capacity, therefore by reducing capacity through DSR would mitigate the need to reinforce.

- Roughly, how much investment costs needed for upgrading the network?

Based on above, you would not invest to allow DSR. You would invest in DSR to defer upgrading. The cost needed to defer upgrading is unique to each situation and would be based on the cost that the DSR would prevent. It is also dependent on the nature of the DSR, its reliability, availability and its duration. All these elements would be factored into establishing a cost of DSR.

If you have any further questions, please do not hesitate to get in touch

Mick Walbank
System Planning Manager

Office: 0191 229 4204
Internal: 729 4204

Mobile: 07889 765 280
Mobex: 716 3554

michael.walbank@northernpowergrid.com
www.northernpowergrid.com

-----Original Message-----
From: mnh22@bath.ac.uk [mailto:mnh22@bath.ac.uk]
Sent: 06 November 2014 12:45
To: LTDS
Subject: Ask: Network Upgrade for DSR Implementation

Dear Sir/Madam,

My name is Mohammad Noor Hidayat. I am a PhD student at Department of Electronic and Electrical Engineering, University of Bath.

I am doing a research related to the implementation of Demand Side Response in electricity distribution network.

As we know, the participation from the distribution network opeartor
(DNO) is very important in the implementation of DSR programme. One of the requirement is
by ugrading the distribution network in order to integrate into the smart meter network. However, I have not found adequate information about the following points:

- Which parts of the network should be upgraded by the DNO?
- Roughly, how much investment costs needed for upgrading the network?

I really need your assistance to get those important information.
How and where can I get permission to access those information?

Thank you very much for your attention and consideration.

Sincerely yours,
Mohammad Noor Hidayat
PhD Student
2E-1.22
Department of Electronic and Electrical Engineering University of Bath
BA2 7AY

****
E mail Disclaimer
You agree that you have read and understood this disclaimer and you agree to be bound by its terms.
The information contained in this e-mail and any files transmitted with it (if any) are confidential and intended for the addressee only. If you have received this e-mail in error please notify the originator.
This e-mail and any attachments have been scanned for certain viruses prior to sending but Northern Powergrid Holdings Company nor any of its associated companies from whom this e-mail originates shall be liable for any losses as a result of any viruses being passed on.
No warranty of any kind is given in respect of any information contained in this e-mail and you should be aware that it might be incomplete, out of date or incorrect. It is therefore essential that you verify all such information with us before placing any reliance upon it.
Northern Powergrid Holdings Company
Lloyds Court
78 Grey Street
Newcastle upon Tyne
NE1 6AF
Registered in England and Wales: Number 3476201
****

Email 2. LTDS <LTDS@northernpowergrid.com>, 10 November 2014. *Network Upgrade for DSR Implementation*. Email to Mohammad Noor Hidayat <mnh22@bath.ac.uk>

Date: 11/10/14 12:48:22 GMT
From: LTDS <LTDS@northernpowergrid.com>
To: mnh22@bath.ac.uk <mnh22@bath.ac.uk>
Subject: RE: Network Upgrade for DSR Implementation

Parts:	0	Alternative part	34 KB
	1	Text part	17 KB
	2	Text part	18 KB

Hi Mohammad

Strange that the link didn't work. The ENA is the trade association for the distribution companies in the UK. The following link may be of help about the Smarter Networks Portal. Mainly a contact name if it does not work

http://www.energynetworks.org/electricity/smart-grid-portal/ena-smarter-networks-portal.html

Unfortunately the schemes are all individual and we do not have a consolidated list.

Answers to your questions are below

-----Original Message-----
From: mnh22@bath.ac.uk [mailto:mnh22@bath.ac.uk]
Sent: 10 November 2014 08:29
To: LTDS
Subject: Re: Network Upgrade for DSR Implementation

Dear Mick Walbank,

First of all, I would like to thank you for your quick response.

I have checked all the links you provided and I got valuable information from them, but the following one is not accessible:
http://www.smarternetworks.org/

Furthermore, I would like to discuss another important factor, i.e.
the costs for DSR Implementation.

According to Peter Bradley, et al (2011), there are two types of DSR Costs, i.e. the participant costs and the system costs. The details are as follows:

The participant costs include: enabling technology investment (smart meter), comfort/inconvenience costs, reduce amenity/lost business, rescheduling costs (e.g. overtime pay) and on-site generator fuel and maintenance costs

The system costs include: metering/communication system upgrades, utility equipment or software costs, billing system upgrades, consumer education, programme/administration/management, marketing/recruitment, payments to participating customers and programme evaluation.

Based on the above information, there are two points that come to my mind:

1. Which one of those two becomes the DNO's responsibility?
(In my opinion, the DNO should bear the system costs but I have not got related evidences/references).
Depending on your standpoint, you could define it either way. Two examples are given below.

New Customer
Under the current regulations, the DNO is responsible for general load growth and maintenance. The cost of this activity is levied on the customer through their electricity bill (on average about £40 per quarter is for the DNO use of system charge) Where we have to upgrade the network to connect a large customer, the total cost is picked up by the customer. The use of DSR would be instead of reinforcement of the network. Therefore any cost associated with DSR would be the responsibility of that particular customer – including any systems, communications etc. A general rule has been that a domestic customer should not see their bill go up due to us connecting a commercial operation, and as all our revenue is recovered from the customer, any ownership on our part would be passed through to the domestic customer.

So in the above example – which is the connection of a new customer – we would expect all participant and system costs to be picked up by the customer. The alternative is for the customer to pay for reinforcement and a Cost Benefit Analysis would work that out.

General load growth
A second example would be general load growth and DSR used as an alternative to reinforcement. In this scenario, it is the general usage by customers that would cause the need to either reinforce or install DSR. We are obligated under our licence to provide the 'most efficient and technically feasible solution' which does include DSR. In this scenario we would expect that any customer involved in DSR would be compensated for inconvenience costs, lost business, fuel etc AND we would cover the cost of software, billing systems, education etc. We would look at going out to some form of tendering process for the services.

A simplistic view would be that the customer would wrap up all their costs into a single price (common approach is an availability price and a utilisation price) and we would use that price as the cost of DSR. We would then look at this price and undertake cost benefit analysis against reinforcement (i.e. building a new substation). The essence of this is the same as above, the most efficient, technically feasible solution – which does not necessarily mean the cheapest, but must be long term viable and cost effective.

2. How to value the costs that fall onto the DNO's responsibility?
(Perhaps there are some available documents that I can access)
There are three places where you can garner information on costs, both will need some analysis to extract what you are after as the actual figures are dependent on the actual project. The best starting point is our RIIO plan – see link below

http://www.yourpowergridplan.com/som_download.cfm?t=media:documentmedia&i=1707&p=file

You can work out unit costs from the details as we give the total cost and the volume and from there you can work out a unit cost.

A second point is also on our website, link below https://www.northernpowergrid.com/quick-calculator

This will give you a ‘ball park’ figure to connect say a single domestic property. You can take the cost of a new connection as a proxy for the cost of reinforcement (i.e. the cost of laying a new cable to add 20kVA is much the same as laying a new cable to increase the capacity by 20kVA) any DSR scheme would have to be economically more efficient and technically feasible and more than just one year. A general guide is 10 to 15 years. This is a good starting point for Cost Benefit Analysis.

In both cases, the starting point is the cost of reinforcement – and any DSR scheme would have to be economically more efficient than the reinforcement cost.

National Grid already have contracts in place DSR services – under the reserve contracts that they release through STOR (Short Term Operating Reserve) as a balancing activity

http://www2.nationalgrid.com/UK/Services/Balancing-services/Reserve-services/Short-Term-Operating-Reserve/Short-Term-Operating-Reserve-Information/

This will give you prices that were paid for DSR on a large scale. This is a good starting point as this market has been around for at least 10 years and is well established. What it does do is set the price in that any scheme that you assess, it would need to be cheaper than this to work.

Thank you very much for your attention and kind assistance.

Sincerely yours,
Mohammad Noor Hidayat

Quoting LTDS <LTDS@northernpowergrid.com<mailto:LTDS@northernpowergrid.com>>:

[Hide Quoted Text]
Dear Mohammad

You may find some useful information on your request in our Long Term
Development Statement. Link below

http://www.northernpowergrid.com/long-term-development-statement

There is no charge for accessing the information and it provides quite
a lot of background data.

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http://www.smarternetworks.org/

both websites will provide you projects and innovations that DNOs are
looking at - these cover all aspects, however amongst these are
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upgrading the distribution network to integrate Smart Metering To
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If you have any further questions, please do not hesitate to get in touch

Mick Walbank
System Planning Manager

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michael.walbank@northernpowergrid.com<mailto:michael.walbank@northernpowergrid.com>
www.northernpowergrid.com<http://www.northernpowergrid.com>

-----Original Message-----
From: mnh22@bath.ac.uk<mailto:mnh22@bath.ac.uk> [mailto:mnh22@bath.ac.uk]
Sent: 06 November 2014 12:45
To: LTDS
Subject: Ask: Network Upgrade for DSR Implementation

Dear Sir/Madam,

My name is Mohammad Noor Hidayat. I am a PhD student at Department of Electronic and Electrical Engineering, University of Bath.

I am doing a research related to the implementation of Demand Side Response in electricity distribution network.

As we know, the participation from the distribution network opeartor (DNO) is very important in the implementation of DSR programme. One of the requirement is by ugrading the distribution network in order to integrate into the smart meter network. However, I have not found adequate information about the following points:

- Which parts of the network should be upgraded by the DNO?
- Roughly, how much investment costs needed for upgrading the network?

I really need your assistance to get those important information.
How and where can I get permission to access those information?

Thank you very much for your attention and consideration.

Sincerely yours,
Mohammad Noor Hidayat
PhD Student
2E-1.22
Department of Electronic and Electrical Engineering University of Bath
BA2 7AY

Email 3. Anna Rossington <Anna.Rossington@ofgem.gov.uk>, 4 April 2013. *DG Incentive Calculation*. Email to Mohammad Noor Hidayat <mnh22@bath.ac.uk>

Date: 04/04/13 17:49:40 GMT
From: Anna Rossington <Anna.Rossington@ofgem.gov.uk>
To: mnh22@bath.ac.uk <mnh22@bath.ac.uk>
Subject: RE: Asking about the calculation process of the DG Incentive Rate

Parts: 1 Text part 9 KB

Apologies - it's a Microsoft Excel function:

PMT function
Calculates the payment for a loan based on constant payments and a constant interest rate.

Syntax

PMT(rate,nper,pv,fv,type)

For a more complete description of the arguments in PMT, see the PV function.

Rate is the interest rate for the loan.

Nper is the total number of payments for the loan.

Pv is the present value, or the total amount that a series of future payments is worth now; also known as the principal.

Fv is the future value, or a cash balance you want to attain after the last payment is made. If fv is omitted, it is assumed to be 0 (zero), that is, the future value of a loan is 0.

Type is the number 0 (zero) or 1 and indicates when payments are due.

Anna

-----Original Message-----
From: mnh22@bath.ac.uk [mailto:mnh22@bath.ac.uk]
Sent: 04 April 2013 15:49
To: Anna Rossington
Subject: Re: Asking about the calculation process of the DG Incentive Rate

Dear Anna Rossington,

I understand all calculation processes you provided, except this particular one:

The annual incentive rate = PMT (WACC, 15, total incentive)
= PMT (5.6%, 15, £9/kW)
= £0.9/kW/yr for 15 years

What does "PMT" mean? How the process should be done?

Could you explain, please?
I really did not get into it.

Thank you very much for your attention and helpful assistance

Sincerely yours,
Mohammad Noor Hidayat

Quoting Anna Rossington <Anna.Rossington@ofgem.gov.uk>:

[Hide Quoted Text]
Dear Mohammad,

The DG incentive is made up of two elements, pass through (80% of the cost of relevant connection assets) and the incentive (per kW). Together they are designed to give the company an additional 1% return on the cost of relevant assets used to connect DG.

The calculation process was as follows:

Pass through revenue = pass through rate x average cost of connection assets
= 80% x £34/kW
= £27/kW

The desired return on the cost of assets used = WACC + 1% = 5.6% + 1%
= 6.6%

The combined revenue/kW (including pass through and incentive) to give the desired return
= average cost of connection assets x (1 + desired return)
= £34/kW x (1 + 6.6%)
= £36/kW

Therefore the total incentive required = combined revenue/kW - pass through revenue/kW
= £36/kW - £27/kW
= £9/kW

The annual incentive rate = PMT (WACC, 15, total incentive)
= PMT (5.6%, 15, £9/kW)
= £0.9/kW/yr for 15 years

Regards
Anna

-----Original Message-----
From: mnh22@bath.ac.uk [mailto:mnh22@bath.ac.uk]
Sent: 25 March 2013 10:50
To: Anna Rossington
Subject: Re: Asking about the calculation process of the DG Incentive Rate

Dear Anna Rossington,

Regarding the Annual Incentive Rate of £0.90/kW/yr, I tried the calculation process as follows:

Annual Incentive Rate
= ((pre-tax WACC / 15) * pass through revenue) * incentive rate required/kW = ((5.6% / 15) * £27) *£9 = £0.9072 /kW/yr

Is the calculation process correct?
If the answer is YES, why the pre-tax WACC must be multiplied by the pass through revenue?

If the calculation process is wrong, how to derive the value of the annual incentive rate?

Or
Could you give me the references/documents which are related to this matter?

Thank you very much for your assistance and consideration.

Sincerely yours,
Mohammad Noor Hidayat
2E-1.22
Department of Electronic and Electrical Engineering Faculty of Engineering and Design University of Bath Bath, BA2 7AY United Kingdom

Quoting Anna Rossington <Anna.Rossington@ofgem.gov.uk>:
Dear Mohammad,

The average connection cost for DG forecast by the DNOs equated to approx £34/kW

The incentive was calculated as follows:

Average connection cost	£34	/kW
pass through rate	80%	
pass through revenue /kW	£27	/kW
additional return	1%	
desired return	6.60%	(on pre-tax WACC of 5.6%)
combined revenue /kW given desired return	£36	/kW
Incentive rate required	£9.00	/kW (£36 - £27)
Annual Incentive Rate	£0.90	/kW/yr (using pre-tax WACC over 15 years)
Rounded up to	£1.00	/kW/yr

I hope this helps

Regards
Anna Rossington

Anna Rossington

Head of RIIO-ED1
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SW1P 3GE

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----- Original Message -----
From: mnh22@bath.ac.uk [mailto:mnh22@bath.ac.uk]
Sent: Monday, February 11, 2013 04:06 PM
To: Rachel Fletcher
Subject: Asking about the calculation process of the DG Incentive Rate

Dear Rachel Fletcher,

My name is Mohammad Noor Hidayat. I am a PhD student at the University of Bath, Bath, United Kingdom. I am doing a research with a topic related to DG Incentives for the Distribution Network Operators in the United Kingdom.

According to the Electricity Distribution Price Control Review - Final Proposals - Incentives and Obligations, page 18, which was published on 7 September 2009, the value of DG incentive rate was set at £1/kW/year. I am curious how this value was derived.

I found on page 19, point 3.6 and 3.11, consists of the following statements:

3.6. The DG incentive is calculated to provide DNOs with an additional rate of return of 1 per cent above the current allowed cost of capital. As stated in Initial Proposals, using use of system connection assets only, the equivalent cost to that used in DPCR4 is £34/kW which resulted in an incentive rate of £1/kW/year in Initial Proposals. We recalculated the DG incentive (using the same basis as used for Initial Proposals) to reflect the WACC of 4.7 per cent (vanilla, equivalent to 5.6 per cent pre-tax) proposed in these Final Proposals. This resulted in a small reduction in the incentive rate, but due to the uncertainty surrounding the DG forecasts, we propose to retain the DG incentive rate at £1/kW/year (pre-tax).

3.11. Similarly, we propose to calculate the DG incentive rate based on use of system connection assets only. The calculation still gives the DNOs an additional rate of return of 1 percentage point above the DPCR5 pre-tax WACC of 5.6 per cent and gives an incentive rate of £1/kW/year (pre-tax). We propose to use the same DG incentive rate for all DNOs in DPCR5.

Until now, I still cannot find the calculation process to get the incentive rate of £1/kW/year. Could you tell me how this value was derived and calculated?

Thank you very much for your assistance.

Sincerely yours,
Mohammad Noor Hidayat
2E-1.22
Department of Electronic and Electrical Engineering Faculty of Engineering and Design University of Bath Bath, BA2 7AY United Kingdom

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Appendix 5 - Papers Published or in Process for Publication

The following papers are reproduced in this appendix, in which, the first three papers have been published and the last one is waiting for publication.

Published papers;

1. Mohammad Noor Hidayat and Furong Li, 2011. Implementation of Renewable Energy Sources for Electricity Generation in Indonesia. *2011 IEEE PES General Meeting*, IEEE Catalogue Number CFP11POW-USB, ISBN 978-1-4577-1001-8.

2. Mohammad Noor Hidayat and Furong Li, 2013. Impact of Distributed Generation Technologies on Generation Curtailment. *2013 IEEE PES General Meeting*, IEEE Catalogue Number CFP13POW-USB, ISBN 978-1-4799-1301-5.

3. Mohammad Noor Hidayat and Furong Li, 2013. Investigating the Impact of Distributed Generation on Demand-dominated Areas. *UKSim-AMSS 7th European Modelling Symposium 2013*, 20-22 November 2013 Manchester, Manchester pp. 378-383.

Papers waiting for publication;

4. Mohammad Noor Hidayat and Furong Li, 2014. Energy-Based Distributed Generation Incentives for Distribution Network Operators. Accepted and scheduled for presentation at *2015 IEEE PES General Meeting.*